D.P.U. 94-49

Petition of Boston Edison Company, pursuant to General Laws Chapter 164, §§ 69I, 76, 94, and 94A, and 220 C.M.R. §§ 10.00 et seq. for review of the procedures by which additional energy resources are planned, solicited, and procured by Boston Edison Company.

APPEARANCES:

Douglas S. Horan, Esq.
William S. Stowe, Esq.
Wayne R. Frigard, Esq.
Catherine J. Keuthen, Esq.
Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199
FOR: BOSTON EDISON COMPANY
Petitioner

L. Scott Harshbarger, Attorney General
By: Kevin J. McNeely
Assistant Attorney General
131 Tremont Street
Boston, Massachusetts 02111
Intervenor

Representative J. James Marzilli
State House Room 236
Boston, Massachusetts 02133
Limited Participant

Michael B. Meyer, Esq.
Meyer, Connolly, Sloman & MacDonald
12 Post Office Square
Boston, Massachusetts 02109
FOR: DIVISION OF ENERGY RESOURCES
Intervenor

John Cope-Flanagan, Esq.
COM/Energy Services Company
One Main Street, P.O. Box 9150
Cambridge, Massachusetts 02142-9150
FOR: COMMONWEALTH ELECTRIC COMPANY AND
CAMBRIDGE ELECTRIC LIGHT COMPANY
Intervenor

Edward L. Selgrade, Esq.
1050 Waltham Street
Lexington, Massachusetts 02173
FOR: BEACON ENERGY COMPANY
Intervenor

Andrew J. Newman, Esq.
Rubin and Rudman
50 Rowes Wharf
Boston, Massachusetts 02110
FOR: THE ENERGY CONSORTIUM
Intervenor

Robert J. Keegan, Esq.
David S. Rosenzweig, Esq.
Maribeth Ladd, Esq.
Keohane and Keegan
21 Custom House Street
Boston, Massachusetts 02110
FOR: ALGONQUIN GAS TRANSMISSION COMPANY
Intervenor

Peter W. Brown
New England Cogeneration Association
1040 Great Plains Avenue
Needham, Massachusetts 02192
FOR: NEW ENGLAND COGENERATION ASSOCIATION
Intervenor

Stephen Klionsky, Esq.
Western Massachusetts Electric Company
260 Franklin Street 21st Floor
Boston, Massachusetts 02110-3179
FOR: WESTERN MASSACHUSETTS ELECTRIC
COMPANY
Intervenor

Mary Beth Gentleman, Esq.
James K. Brown, Esq.
Foley, Hoag & Elliot
One Post Office Square
Boston, Massachusetts 02109
FOR: ALTRESCO LYNN, LIMITED PARTNERSHIP
Intervenor

John A. DeTore, Esq.
Robert D. Shapiro, Esq.
Rubin and Rudman
50 Rowes Wharf
Boston, Massachusetts 02110-3319
FOR: COALITION OF NONUTILITY GENERATORS, INC.
Intervenor

Paul W. Gromer, Esq.
Massachusetts Energy Efficiency Council, Inc.
60 Thoreau St., Suite 234
Concord, Massachusetts 01742-9116
FOR: MASSACHUSETTS ENERGY EFFICIENCY COUNCIL, INC.
Intervenor

Paul Burns, Esq.
Massachusetts Public Interest Research Group
29 Temple Place
Boston, Massachusetts 02111
FOR: MASSACHUSETTS PUBLIC INTEREST RESEARCH GROUP
Intervenor

Alan Wilson, Esq.
Conservation Law Foundation
62 Summer Street
Boston, Massachusetts 02110-1008
FOR: CONSERVATION LAW FOUNDATION, INC.
Intervenor

Thomas G. Robinson, Esq.
New England Power Service Company
25 Research Drive
Westborough, Massachusetts 01582
FOR: MASSACHUSETTS ELECTRIC COMPANY
Limited Participant

Paul Messerschmidt
Energy Risk Management Council c/o BMAI
45 Broad Street 4th Floor
Boston, Massachusetts 02109-4807
FOR: ENERGY RISK MANAGEMENT COUNCIL
Limited Participant

Thomas P. O'Neill, Esq.
Boston Gas Company
One Beacon Street
Boston, Massachusetts 02108
FOR: BOSTON GAS COMPANY
Limited Participant

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I. INTRODUCTION

A. Procedural History

On March 15, 1994, Boston Edison Company ("BECo" or "Company") submitted its draft initial filing pursuant to 220 C.M.R. §§ 10.00 et seq., the integrated resource management ("IRM") regulations and the Department of Public Utilities' ("Department") Order in Boston Edison Company, D.P.U. 92-265 ("D.P.U. 92-265") (1993).[1] The Department issued an Order of Notice, directing the Company to post and publish notification of the Company's filing in accordance with the provisions of the IRM regulations.

In accordance with G.L. c. 12, § 11E, the Office of the Attorney General ("Attorney General") intervened in this proceeding. Western Massachusetts Electric Company, Commonwealth Electric Company and Cambridge Electric Light Company ("Com/Energy"), Conservation Law Foundation ("CLF"), Massachusetts Public Interest Research Group ("MASSPIRG"), the Energy Consortium ("TEC"), the Coalition of Non-Utility Generators, Inc. ("CONUG"), the New England Cogeneration Association, Altresco Lynn Limited Partnership ("Altresco"), Beacon Energy Company, Algonquin Gas Transmission Company ("Algonquin"), and Massachusetts Energy Efficiency Council ("MEEC") were allowed to intervene in this proceeding. Massachusetts Electric Company ("MECo"), Boston Gas

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[1] In D.P.U. 92-265, the Department approved an Offer of Settlement which required the Company to submit the draft initial filing on March 15, 1994, and its initial filing on July 15, 1994.

Company ("BGC"), Energy Risk Management Council, and Representative J. James Marzilli were allowed to participate as limited participants.[2]

Pursuant to notice duly issued, the Department conducted a technical session on April 21, 1994 and a public hearing on April 28, 1994. On July 15, 1994, the Company submitted its initial filing. The Department conducted three prehearing conferences,[3] and twenty-one evidentiary hearings.[4]

The Company presented sixteen witnesses in support of its filing: Thomas J. May; Geoffrey O. Lubbock; Michael M. Schnitzer; Robert J. Cuomo; Ellen K. Angley and Edward P. Mcguire;[5] Thomas C. Murrell; Paul D. Vaitkus; Jacob J. Scheffer; John J. Reed; Rose Anne Pelletier; Scott M. Albert; Richard S. Hahn; William C. Rothert;[6] Kathleen A. Kelly; and Gerald E. Cain.[7] Messrs. Lubbock and Schnitzer also testified as rebuttal witnesses.

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2 MECo filed a petition to intervene as a limited party and BGC filed a petition to intervene as an interested party. For purposes of this proceeding, both MECo's and BGC petitions are treated as petitions to participate as limited participants.

3 Prehearing conferences were conducted on August 10, 1994, August 30, 1994, and September 22, 1994.

4 Evidentiary hearings were commenced on September 29, 1994 and were concluded on November 4, 1994.

5 Ms. Angley and Mr. McGuire submitted joint prefiled testimony and testified as a panel.

6 The Company submitted the prefiled testimony of Leon J. Olivier. Due to unavailability, Mr. Olivier did not testify and Mr. Rothert testified on issues covered by Mr. Olivier's prefiled testimony.

7 Ms. Kelly and Mr. Cain did not submit prefiled testimony.

In addition, the Attorney General presented the testimony of Paul L. Chernick, CLF and MASSPIRG presented the testimony of Joseph M. Chaisson and Alan J. Nogee, and MEEC presented the testimony of John H. Manning and Harvey G. Michaels.[8] The evidentiary record consists of 1106 exhibits and responses to 152 Record Requests.

Pursuant to a briefing schedule established by the Department, initial briefs were submitted by the Company, the Attorney General, CLF and MASSPIRG (jointly), CONUG,[9] and MEEC.[10] Reply briefs were submitted by the Company, the Attorney General, CLF/MASSPIRG, CONUG, MEEC, Com/Energy, TEC and Representative Marzilli.

As a result of the extensive discovery and the due process considerations afforded the Company and parties, on December 13, 1994, pursuant to 220 C.M.R. § 10.07(5) the Department issued an exception to 220 C.M.R. § 10.03(11)(b), the requirement that the Department complete its review and issue an Order within five months of the Company's

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8 Pursuant to 220 C.M.R. § 1.10(4), Mr. Michaels' prefiled testimony was marked as an exhibit, but he did not testify.

9 In its initial brief, CONUG stated that Altresco endorsed the positions set forth.

10 By letter dated November 21, 1994, Algonquin stated that it would not be filing an initial brief and reserved the right to submit a reply brief.

initial filing.[11] The Department stated that it would issue its Order no later than January 13, 1995.

B. Scope of Review

The IRM process consists of four phases. Phase I involves the Company's submittal of the draft initial filing and initial filing and the Department's review of those filings. The IRM regulations require that the initial filing contain the Company's demand forecast, resource inventory, evaluation of resource need, evaluation of resource potential, resource solicitation request for proposals ("RFP"), and initial resource portfolio. In Phase II, the Company issues the Department-approved RFP(s). In Phase III, the Department reviews the Company's resource mix and award group and in Phase IV, the Department reviews and approves contracts resulting from any resource solicitation.

In Phase I, the IRM regulations provide for Department review of an electric company's demand forecast, resource inventory, evaluation of resource need, and identification of the technical potential of demand-side resources and technical potential of life extension and repowering of power plants. 220 C.M.R. § 10.01(2)(a). Consistent with Department's findings on the Company's demand forecast, the Department may adjust or modify the Company's evaluation of resource need. 220 C.M.R. § 10.03(6)(a).

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11 The IRM regulations established a five-month period from the date of the Company's Initial Filing for the Department to complete its Phase I review. In promulgating the IRM regulations, the Department and Siting Council noted that the process may take longer than the review periods established by the regulations if all issues must be adjudicated. Siting Council Order on Proposed IRM Rulemaking, 20 DOMSC 222, at 241 (1990). The Department and Siting Council expected that as the regulatory agencies and parties to the proceedings gain experience with the IRM process, the time periods contemplated by the regulations would be adequate. Id.

The IRM regulations provide that, in response to any identified need for additional capacity resources, an electric company shall have the option to issue a single RFP for all resources or to issue separate RFPs for supply-side and demand-side resources. 220 C.M.R. § 10.03(10)(b). The regulations further provide that if no additional capacity need has been identified through the forecast period, any RFPs shall be for energy or energy savings only. 220 C.M.R. § 10.03(10)(c).[12] Because the Company has forecasted no need for additional capacity resources through the forecast period, the initial filing included an RFP for energy savings only.[13]

In Section II of this Order, the Department reviews the Company's demand forecast. In Section III of this Order, the Department reviews the Company's resource inventory of existing and planned resources. In Section IV of this Order, the Department makes findings on the Company's need for additional capacity resources based on the contribution of existing and planned resources to the demand forecast. In Section V of this Order, the Department reviews the Company's resource procurement plans including the RFP(s) submitted by the Company.

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12 The Department has stated that electric companies that participate in the short-term energy market will not be required to issue a supply-side energy-only RFP through the IRM process. See D.P.U. 93-154.

13 Pursuant to the Offer of Settlement approved by the Department in D.P.U. 92-265, the Company submitted a supply-side capacity RFP for discussion purposes only (Exh. BE-1, at C.1-1).

II. ANALYSIS OF THE COMPANY'S DEMAND FORECAST

A. Standard of Review

Pursuant to G. L. c. 164, § 69I, the review of electric company forecasts is performed by the Department. G. L. c. 25, § 12M provides, in pertinent part, that the Department shall adopt integrated resource management regulations to oversee the long-term planning processes of electric companies, to ensure that said companies are planning adequately to provide reliable energy for the Commonwealth. The IRM regulations set out the specific filing requirements for an electric company's demand forecast. See 220 C.M.R. § 10.03(6). An electric company must describe the following components of its forecast methodology for each year of the forecast period: (1) the major determinants of total annual electric energy demand and seasonal peak demand; (2) the source and vintage of the major data components used; (3) the methodologies used to acquire, organize, modify, and test the validity of data used; (4) the major models used in compiling the forecast; (5) the level of confidence associated with key dependent and independent variables used in the models; and (6) the major assumptions regarding the forecast. 220 C.M.R. § 10.03(6)(c).

The regulations provide that an electric company's projections of the demand for electricity shall be based on substantially accurate historical information, and upon reasonable statistical projection methods. 220 C.M.R. § 10.03(6)(a). The electric company shall demonstrate that the demand forecast is reviewable, appropriate, and reliable. Id. A demand forecast is reviewable if it contains enough information to allow a full understanding of the forecasting methodology. Id. The Department does not prescribe a particular methodology that must be used by an electric company in forecasting demand. 220 C.M.R.

§ 10.03(6)(c). A forecast is appropriate if the methodology used to produce the forecast is technically suitable to the size and nature of the utility that produced it. 220 C.M.R. § 10.03(6)(a). A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur Id. See Commonwealth Electric Company and Cambridge Electric Light Company, D.P.U. 91-234 (1993) ("D.P.U. 91-234"); See also, Boston Edison Company, 24 Decisions and Orders of the Massachusetts Siting Council ("DOMSC") 125 (1992) ("1992 BECo Decision").

B. Energy Forecast

1. Employment Forecast

a. The Company's Proposal

BECo stated that it developed a forecast of territory employment for use in the Company's commercial energy and industrial energy forecasts. (Exh. BE-1, Book 2, at F.A-10). The Company projected total employment in its service territory to grow from approximately 985,000 jobs in 1994 to approximately 1,113,000 jobs in 2004, a compound annual growth rate of 2.3 percent (id. at 16). The Company stated that its employment forecast was based on a similar methodology to that previously approved by the Energy Facilities Siting Council (Exh. BE-5, at 5). The Company indicated that it specified separate econometric equations to model territory employment in the commercial sector by twelve building types and ten employment classifications, and in the industrial sector by 19 Standard Industrial Classifications ("SICs") (Exh. BE-1, Book 2, at F.A-10). The Company stated that its employment forecast used historical territory employment data from the years of 1967 through 1992, and economic projections from the Data Resources, Inc. ("DRI") February 1994 forecasts of the Massachusetts and U.S. economies (id. at 10, 11; Exh. BE-1, Book 1, at A.1.0 (Update); Tr. 2, at 11).[14]

The Company stated that it conducted statistical tests to analyze the validity of the econometric equations used in the employment forecast (Tr. 2, at 17). BECo stated that it applied R-squared, T-statistic, and Durbin-Watson tests to the equations of its employment forecast model to gauge statistical significance (id.).[15]

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[14] In addition to DRI's February 1994 forecast of the Massachusetts economy, on which the Company's filing is based, the Company provided DRI's August 1994 forecast of the Massachusetts economy (Exh. CON-IR-8-20S). DRI's August 1994 forecast of the Massachusetts economy projected non-manufacturing employment levels in Massachusetts to grow from 2.48 million jobs in 1994 to 2.89 million jobs in 2004 (id.). DRI's February 1994 forecast of the Massachusetts economy projected non-manufacturing employment levels in Massachusetts to grow from 2.38 million jobs in 1994 to 2.82 million jobs in 2004 (Exh. CON-IR-1-57). Relative to the February 1994 DRI forecast, the August 1994 DRI forecast projected between 78,000 and 102,000 more non-manufacturing jobs in Massachusetts for 1994 through 2004 respectively (Exh. CON IR-8-20S; Exh. CON IR-1-57). The Company indicated that the higher employment levels reflected in the August 1994 DRI data reflected a "rebenchmarking," or revision, of historical employment data by the U.S. Bureau of Labor Statistics rather than any significant change in actual levels of employment (Exh. CON-IR-8-41).

[15] R-squared is a statistical measure of the amount of variation in a dependent variable which is explained by the variation in one or more independent variables. R-squared values range between 0.00 and 1.00, where 0.00 indicates no variation explained by the independent variables and where 1.00 indicates complete explanation by the independent variables. Boston Edison's commercial employment equations produced r-squared values of 0.82 or above, except for the equations for grocery stores (0.55), transportation, communication and utilities (0.50), and private schools (0.48) (Exh. BE-1, Book 2, at F.A-17 to F.A-19). Boston Edison's industrial employment equations produced R-squared values of 0.75 or above, except for the equations for lumber and wood (0.62), and primary metals (0.74) (id. at F.A-21 to F.A-22).

b. Positions of the Parties

i. CONUG

CONUG argues that BECo's forecasting model understates the number of jobs in Massachusetts (CONUG Initial Brief at 26). CONUG maintains that the effect of underforecasting employment is to reduce the Company's peak load forecast (id.). CONUG states that the actual number of non-manufacturing jobs in Massachusetts at the end of 1993 was 60,000 jobs higher than the amount reflected in DRI's February 1994 forecast of Massachusetts non-manufacturing employment and used in the Company's forecast (id.). In addition, CONUG argues that the U.S. Department of Labor's Bureau of Labor Statistics data indicate that the number of jobs in Massachusetts has increased by over 80,000 since 1993 (id. at 26-27). CONUG maintains that there were actually over 89,000 more non-manufacturing jobs in Massachusetts in 1994 than the number estimated by the Company (id. at 27). In support of CONUG's contention that the BECo forecast understates non-manufacturing employment, CONUG argues that, for the years of 1995 through 1998, BECo's forecast of the rate of growth of non-manufacturing employment for the Boston Edison service territory is lower than DRI's forecast for the state as a whole (id. at 33).

ii. The Company

BECo responds that CONUG's argument regarding commercial employment is not valid because the additional non-manufacturing jobs in Massachusetts reflected in DRI's August 1994 forecast were based on an upward revision, or rebenchmarking, of historical employment data. (BECo Reply Brief at 26).

c. Analysis and Findings

In the previous review of the Company's demand forecast, the Energy Facilities Siting Council ("Siting Council") approved BECo's employment forecasting methodology (1992 BECo Decision, at 22, 24). The Siting Council approved the use of territory-specific employment data, economic projections from a widely-accepted firm, and econometric techniques to forecast territory-specific employment. Id. The Department has conducted a review of the Company's employment forecasting methodology in this proceeding and notes that the methodology is generally consistent with the Department's precedent. Id. Thus, the Company's employment forecast is based upon a well-established methodology.

With respect to CONUG's argument that the Company's forecast model understates the actual number of non-manufacturing jobs in Massachusetts, the Department notes that the DRI's August 1994 employment data do, in fact, project higher non-manufacturing employment levels in Massachusetts over the forecast period than those reflected in the August 1993 DRI forecast and the February 1994 DRI forecast. However, the record in this case indicates that the higher employment levels reflected in the more recent DRI data were based on the Bureau of Labor Statistics' rebenchmarking of historical employment data. Moreover, the record provides no clear indication that the Company's energy and peak load forecasts would be significantly understated as a result of employment levels reflected in DRI's August 1994 forecast. Therefore, the Department does not accept CONUG's argument that BECo's forecasting model understates the number of jobs in Massachusetts.

The Department further notes that the Company's filing did not include a sensitivity analysis demonstrating the responsiveness of the peak load forecast to changes in historical and projected employment levels. Absent such an analysis, it is difficult for the Department to reach firm conclusions regarding the reliability of the Company's employment forecasting methodology.

The record shows that, while most of the Company's employment forecast equations produce strong statistical results, the equations used to forecast commercial employment in grocery stores, transportation, communication and utilities warehouses, and private schools produce R-squared values that were considerably lower than the R-squared values produced by the equations used to predict employment in the remaining commercial sectors. Similarly, the equation used to forecast employment in the lumber and wood industry produced an R-squared value that was considerably lower than the R-squared values produced by the equations used to predict employment in the remaining industrial sectors. The Department notes that in the previous review of the Company's employment forecast, the Energy Facilities Siting Council identified statistical weaknesses associated with the equations then used to forecast employment in the same building types and sectors as those that produce weak results in the instant case. See 1992 BECo Decision at 18, 19. The Department recognizes that R-squared is merely one measure of the strength of the relationship between variables, and that the incorporation of logic and sound judgement in the choice of relevant independent variables and the specification of econometric equations is also required to produce a reliable forecast. However, the Department is concerned that the low R-squared values produced by the equations mentioned above could be indicative of the use of predictor variables that do not adequately capture the dynamics that contribute to employment in the sectors noted above. The record in this case demonstrates that the Company's employment forecast represents a key input to BECo's energy and peak load forecasts. It is therefore important that particular attention be paid to obtaining reliable results from the employment forecast.

Based on the foregoing, the Department finds that, because its filing contains enough information to allow a full understanding of the employment forecasting methodology, it is reviewable. In addition, the Department finds that, because the methodology used to produce the employment forecast is only minimally suitable to the size and nature of the utility that produced it (i.e., BECo provided no sensitivity analysis), it is minimally appropriate. Finally, the Department finds that, because the Company's employment forecast methodology provides only a limited measure of confidence that its data, assumptions, and judgments will produce a forecast of what is most likely to occur, it is minimally reliable. In order for the Department to approve the employment forecast in the Company's next IRM filing, the Company must furnish (1) a sensitivity analysis demonstrating the responsiveness of energy sales forecasts and the peak load forecast to changes in historical and projected employment levels; and (2) a comparative analysis of alternative equation specifications or methodologies to improve the predictive capabilities of the employment forecast as it relates to commercial employment in grocery stores, transportation, communication and utilities warehouses and private schools, and industrial employment in the lumber and wood sector.

2. <u>Demographic Forecast</u>

a. <u>The Company's Proposal</u>

BECo developed a demographic forecast to predict the number of residential customers in its service territory (Exh. BE-1, at F.A-8). The Company projected the number of residential customers in its service territory to grow from approximately 570,000 customers in 1994 to approximately 609,000 customers in 2004, a compound annual growth rate of 0.66 percent (Exh. BE-1, Book 1, at A.2-5). The Company indicated that its projection of the number of residential customers is derived from a forecast of population divided by a forecast of average household size (Exh. BE-1, at F.A-7).

The Company stated that the forecast of population was derived by combining the results of projections of births, deaths, and net migration for the BECo service territory (Exh. BE-1, at F.A-6).[16] The Company indicated that birth and death rates were determined by calibrating U.S. Census Bureau data to actual BECo service territory values (id.). In addition, the Company stated that migration to and from the BECo service territory was forecasted using a multiple regression equation with the following independent variables: (1) employment in Middlesex, Norfolk, and Suffolk counties; (2) the Massachusetts labor force; (3) Massachusetts employment in the Finance, Insurance and Real Estate sector; (4) U.S. employment in the Finance, Insurance and Real Estate sector; and (5) U.S. employment in manufacturing (id.). BECo stated that economic data used in its net migration equation was obtained from DRI's August 1993 forecast (id. at F.A-7). BECo indicated that its net migration equation performed well statistically (id.). The coefficients associated with the predictor variables produced "T-statistics" with absolute values of greater than 2.0 (id.). In addition, the migration equation as a whole produced an R-squared value of 0.88 (id.).

16 The record also includes projections of Massachusetts population from the New England Economic Project. (Exh. CON-19).

BECo stated that the forecast of household size was developed by calculating household headship ratios from U.S. Census Bureau data (id.). Headship ratios were calculated for 5-year age groupings and multiplied by the forecasted service territory population for 2013 to derive an initial estimate of the number of households in the Company's service territory (id.). The estimated number of households was divided by the population projection for 2013 to develop an estimate of persons per household in 2013 (id.). The Company indicated that the average household size for 2013 was compared to actual Census data from 1990, and the long-term decrease was calculated on a compound annual basis (id.).

b. Positions of the Parties

i. CONUG

CONUG argues that BECo's projections of population growth are lower than Massachusetts population growth projections supplied by DRI and the New England Economic Project ("NEEP") (CONUG Initial Brief at 34). Consequently, CONUG urges an upward adjustment to the Company's peak load projections, based, in part, upon higher projections of population growth (id. at 38).

ii. The Company

The Company does not address CONUG's argument regarding BECo's population growth projections. With respect to the net migration equation, the Company states that the new specification was the result of extensive regression analysis, and that the variables in the Company's migration equation were able to explain approximately 90 percent of the annual variation in historical net migration to and from the Company's service territory (BECo Initial Brief at 21).

c. Analysis and Findings

In the previous review of the Company's demand forecast, the Siting Council approved BECo's demographic forecasting methodology. 1992 Beco Decision at 27. In its decision, the Siting Council approved the Company's approach to forecasting demographic change in its service territory, including the projection of change in population as a function of births, deaths, and net migration. Id. at 24-25. In addition, the Siting Council approved the Company's use of DRI economic data and U.S. Census Bureau birth and death rate data. Id. at 25. The Department has conducted a review of the Company's demographic forecasting methodology in this proceeding and notes that the methodology is generally consistent with the Department's precedent. Id. at 27. Thus, the Company's demographic forecast is based upon a well-established methodology.

With respect to CONUG's argument that DRI and NEEP forecast higher rates of population growth than the Company projects for its service territory, the Department notes that the BECo service territory may exhibit demographic characteristics that are different from those of Massachusetts as a whole. In addition, the record in this case indicates that the differences in the population growth rates projected by DRI and NEEP for Massachusetts, and by the Company for its service territory, are not great. Therefore, the Department does not accept CONUG's suggestion that the Company's peak load forecast be adjusted upward due to a deficiency in the Company's demographic forecast.

BECo's approach to forecasting population, number of households, and number of customers in its service territory is acceptable. Specifically, the Company's demographic forecast incorporates territory-specific historical data, and projections obtained from a reputable forecasting firm. The Company's net migration equation produces statistical results indicating strength in the predictive capacities of (1) each of the independent variables, and (2) the equation overall. Based on the foregoing, the Department finds that the Company's demographic forecast is reviewable, appropriate and reliable.

3. Electricity Price Forecast

a. The Company's Proposal

The Company developed forecasts of the price of electricity to Boston Edison's residential, commercial, and industrial customers (Exh. BE-1, Book 1, at A.1-2; Book 2, at F.A-1, F.A-2). BECo indicated that the price of electricity is an input into the energy sales forecasts of the residential, commercial and industrial sectors (Exh. BE-1, Book 2, at F.A-2). The Company stated that the electricity prices represented by its forecast were the sum of four separate rate components: (1) a base charge, including Company-owned plant and equipment, and other items treated in base rate cases;[17] (2) a fuel charge, including projected costs of fossil fuel and purchased power;[18] (3) a new performance adjustment

17 The Company stated that the capacity assumptions initially incorporated into the base price forecast came from the Company's previous resource plan filing (BECo Initial Brief at 19).

18 The Company stated that its fuel charge forecast was a function of the cost of fossil fuels, its generating unit mix, and the costs of purchased power (Exh. BE-1, at F.A-2). BECo stated that it evaluated data from five forecasting firms to develop a (continued...)

charge ("NPAC"), consisting of financial incentives or penalties associated with the performance of Pilgrim Station;[19] and (4) a conservation charge (id. at F.A-1).[20]

The Company stated that the forecast of electricity price affected the projected level of electricity demand (Tr. 2, at 73). The responsiveness of the level of energy consumption to electricity price was reflected through the price elasticity factors incorporated into the Company's energy forecasts (id.). The Company further indicated that it did not plan to seek a base rate increase until the year 2000 (Exh. BE-1, at F.A-1). The Company did not provide an analysis of the potential effects on the peak load forecast of a decrease in the price of electricity.

b. Analysis and Findings

Boston Edison's electricity price forecast exhibits several strengths, including (1) the breakdown of the total electricity price into distinct component parts, (2) the application of distinct price growth rates to the individual customer classes, and (3) the development and incorporation of a consensus fuel forecast to account for the wide variation among separate fuel price forecasts. In the past, the Department has approved electricity price forecasting

[18](...continued) "consensus" fossil fuel forecast (id. at 2). The five firms were (1) Pace Consultants, (2) ICF Resources, Inc., (3) Petroleum Industry Research Associates, (4) Foster Associates, Inc, and (5) DRI (id.).

[19] BECo indicated that the NPAC is a Pilgrim Station performance incentive charge that was agreed to as part of the rate settlement in Boston Edison Company, D.P.U. 89-100 (1989)(Exh. BE-1, at F.A-1).

[20] BECo stated that the conservation charge projections would include lost base revenues associated with Company DSM programs, amortization of carrying costs and taxes associated with capitalized Company DSM programs, and annual expenses associated with Company DSM programs (Exh. BE-1, at F.A-1).

methodologies that include (1) the breakdown of the total electricity price into distinct component parts, and (2) the application of distinct price growth rates to the individual customer classes. See Eastern Utilities Associates, D.P.U. 92-214, at 14 (1993) ("D.P.U. 92-214"); See also 1992 BECo Decision, at 29.

The record indicates that BECo failed to address the likelihood of an electricity price decrease, or provide an analysis of the sensitivity of the peak load forecast to increasing and decreasing levels of electricity price. The Department notes that, to the extent that the electricity market becomes more competitive in future years, the Company may be under considerable pressure to decrease its prices. Clearly, such action could lead to increases in customer demand that have not been accommodated in the demand forecast. Despite this weakness, the Company's overall approach to forecasting electricity price is acceptable. Therefore, the Department finds that Boston Edison's electricity price forecast is reviewable, but only minimally appropriate and minimally reliable. In order for the Department to approve the electricity price forecast in the Company's next IRM filing, the Company must (1) furnish a sensitivity analysis demonstrating the responsiveness of the peak load forecast to changes in projected electricity price levels, and (2) address the likelihood of electricity price decreases in light of the Company's stated corporate goals and understanding of the competitive nature of retail electricity markets.

4. Residential Energy Forecast

a. The Company's Proposal

The Company stated that its residential energy forecast was based on a methodology that was similar to the methodology used by the Company in previous forecasts (Exh. BE-1, at F.A-23). BECo projected residential energy consumption to grow from 3,469 gigawatthours ("GWH") in 1994 to 3,813 GWH in 2004, a compound annual growth rate of 0.95 percent (Exh. BE-1, Book 1, at A.1-3 Update).

The Company stated that it forecasted energy consumption associated with 28 different residential end-uses (Exh. BE-1, at F.A-23).[21] BECo indicated that its residential energy forecast was based on three primary components: (1) the number of residential customers; (2) appliance saturation rates, (i.e., the percentage of households owning a particular appliance in any given year); and (3) the average energy consumption per appliance (Exh. BE-1, at F.A-27). The Company stated that the total residential energy forecast was calculated by summing the energy usage of the 28 modelled residential end-uses (id. at 23).

BECo stated that its projections of the number of residential customers was obtained from the results of the demographic forecast (see Section II.B.2, above), which contained projections of population and number of households (Tr. 2, at 61-62). In addition, the

21 The 28 end-use categories were electric range, electric range (self-cleaning), refrigerator (frost-free), refrigerator (standard), refrigerator (second), freezer (frost-free), freezer (standard), dishwasher, room air conditioner, dehumidifier, whirlpool/jacuzzi, electric vehicles, central air conditioner, clothes washer, electric clothes dryer, electric water heater, microwave oven, television (color), television (black & white), electric space heating, heat pump, portable electric heater, video cassette recorder, personal computer, swimming pool pump, whole-house/attic fan, lighting, and "miscellaneous" (Exh. BE-1, at F.A-23). The Company stated that the energy consumption of miscellaneous uses was calculated as a residual (i.e., all energy consumption beyond that specifically attributable too other categories was allocated into the miscellaneous category), and that it included the energy consumption of appliances used for food preparation, personal care, home entertainment, and home maintenance (id. at 24; Tr. 4, at 147).

Company stated that projections of appliance saturation rates were based on saturation-income functions that were derived from responses to the Company's 1991 survey of residential customers and from DRI's real disposable personal income data (Exh. BE-1, at F.A-23).[22]

BECo indicated that base projections of average electricity consumption per appliance were derived from information provided by the Edison Electric Institute, the Association of Home Appliance Manufacturers, NEPOOL, and internal Company sources (id. at 24). Base year average electricity consumption projections were modified by price elasticity factors and federal appliance efficiency standards where applicable (id.).

b. Positions of the Parties

i. CONUG

CONUG contends that the Company's residential energy forecast is understated because the room air conditioner saturation rates fail to take into account ownership of multiple room air conditioners (CONUG Initial Brief at 29). CONUG suggests that this deficiency in the Company's forecast is a contributing factor to the underforecasting of the 1994 summer peak load (See discussion of BECo's peak load forecast in Section II.C, below.) Id. at 25, 29.

[22] One of the residential appliances for which the Company developed a projection of saturation rates was room air conditioners (Exh. BE-1, Book 2, at F.A-23). The Company's filing contained saturation rate projections for room air conditioners that ranged from 72 percent in 1994, to 74 percent in 2004 (Exh. BE-1, Book 1, at A.2-9). BECo subsequently revised the room air conditioner saturation rates to reflect instances of customers owning more than one room air conditioner (Exh. CON-RR-10). The revised saturation rates for room air conditioners ranged from 135 percent in 1994, to 138 percent in 2004 (Exh. DPU-RR-17, Attachment 1).

ii. <u>The Company</u>

The Company responds to CONUG's argument regarding room air conditioner saturation rates by stating that the effect on the residential energy forecast of not accounting for ownership of multiple room air conditioners would be to merely reallocate energy consumption from the room air conditioner end use category to the residual, miscellaneous category of residential energy consumption (BECo Reply Brief at 29). The Company contends that the overall impact of such a reallocation on the residential forecast would be negligible (Tr. 4 at 147).

c. <u>Analysis and Findings</u>

In the past, the Siting Council approved residential energy forecasting methodologies that included disaggregation of end-uses and incorporation of territory-specific survey results. <u>See</u> D.P.U. 92-214, at 20; <u>1992 BECo Decision</u> at 59. The Department has conducted an extensive review of the Company's residential forecasting methodology and notes that the methodology is consistent with the Department's precedent. Thus, the Company's residential forecast is based upon a well-established methodology. <u>1992 BECo Decision</u> at 22, 24. The Company's residential forecast methodology in the instant case includes disaggregation of residential energy consumption into 28 distinct end-use categories, and the incorporation of survey results that provide detailed, service-territory-specific information regarding the residential appliance inventory and customer characteristics.

However, the record indicates that the Company's residential survey did not reflect ownership of multiple room air conditioners. The record further indicates that the energy consumption of room air conditioners that were not accounted for in the residential survey was reflected in the residual, miscellaneous end-use category instead of the room air conditioner end-use category. The Department notes that room air conditioner loads have a far greater impact on summer peak load than loads of the various appliances in the miscellaneous end-use category. Thus, accounting for room air conditioner energy consumption in the miscellaneous category rather than the room air conditioner category would tend to result in an underforecast of residential peak load. As indicated previously, one of the strengths of BECo's residential energy forecasting methodology is that the Company disaggregates energy consumption into 28 distinct end-use categories. The benefit of this strength is largely diminished if the Company's forecast fails to allocate energy consumption to the appropriate end-use categories. Further, the Company's filing in this case does not include an analysis of the sensitivity of peak load to changes in the level of end-use energy consumption. Absent such an analysis, it is difficult for the Department to assess the impact on peak load attributable to underforecasting the number of room air conditioners.

Based on the foregoing, the Department finds, on balance, that the Company's residential energy forecast is reviewable, but only minimally appropriate and minimally reliable. In order for the Department to approve the residential forecast in the Company's next IRM filing, the Company must furnish (1) evidence that projections of appliance saturations accurately reflect ownership of more than one of a particular appliance, and (2) an analysis of the sensitivity of peak load to changes in energy consumption in the various residential end-use categories.

5. Commercial Energy Forecast

a. The Company's Proposal

BECo projected commercial energy consumption to grow from 7,394 GWH in 1994 to 8,097 GWH in 2004, a compound annual growth rate of 0.91 percent (Exh. BE-1, Book 1, at A.1-3 Update). The Company stated that it developed its commercial energy forecast using the disaggregated, end-use model, Commercial Energy Demand Modeling System ("CEDMS") (Exh. BE-1, at F.A-31). BECo indicated that its commercial energy forecasting methodology was largely unchanged from that presented to the Siting Council in the Company's demand forecast filed as part of EFSC 90-12/90-12A (id.).

BECo calculated commercial sector energy use for twelve building types and eight end-uses (id.).[23] The total commercial energy forecast was calculated by summing the forecasted consumption across these end-uses and building types (id.). The resulting forecast was then adjusted for the anticipated effects of electric vehicles energy use and load reductions due to customer self-generation (Exh. BE-1, at F.A-36, F.A-39). BECo stated that CEDMS models commercial energy consumption as a function of three factors: (1) floor space served by energy-using equipment, (2) design "energy use intensities," (or kilowatthours per square foot) and (3) utilization rates (id. at 32). The Company stated that

[23] BECo stated that the twelve building types were offices, restaurants, retail trade buildings, grocery stores, warehouses, elementary/secondary schools, colleges/universities, hospitals, other health services buildings, hotels/motels, public buildings (except office buildings), and miscellaneous buildings (Exh. BE-1, at F.A-31). The Company further stated that the eight end-uses were space heating, air conditioning, ventilation, water heating, cooking, refrigeration, lighting, and a miscellaneous uses category (id.).

it recalibrated the CEDMS model to relevant territory-specific characteristics in 1993 (id. at 31). The base year of the CEDMS model was 1992 (id. at 33).

The Company indicated that a vacancy rate forecast and standard values for square-foot-per-employee, and employment were used to develop a forecast of floor space served by energy-using equipment (id. at 32, 36; Tr. 3, at 55). The square-foot-per-employee standard values were obtained from the Company's 1988 commercial customer survey (Tr. 3, at 55). BECo obtained employment values from its territory employment forecast (Tr. 3, at 55, 57). The vacancy rate forecast was obtained from data provided by F.W. Dodge/McGraw Hill and Cushman and Slye (id. at 51).[24]

The Company stated that base year energy use intensities used in the CEDMS model were obtained from the Company's 1988 commercial customer survey (Exh. BE-1, at F.A-32). Survey data were then reconciled with national data pertaining to energy use intensity by building type and end-use that were provided by a consultant retained by the Company (Tr. 3, at 53).

BECo stated that the rates of actual equipment utilization relative to design usage per square foot were determined through examination of equipment operating costs (Exh. BE-1, at F.A-34). The Company indicated that changes in equipment operating costs were based

[24] The Company stated that F.W. Dodge forecast the vacancy rate for offices to be approximately 23 percent in 1994 (Exh. CON 1-68). The record in this case also includes a greater Boston commercial real estate market report for the third quarter of 1994 prepared by Meredith and Grew (Exh. CON-25). The Meredith and Grew report estimated the office and R&D space vacancy rate for the greater Boston area to be approximately twelve percent for the third quarter of 1994 (id.).

on expected changes in equipment efficiency and/or relative fuel prices in a given forecast year (id.).

b. Positions of the Parties

i. CONUG

CONUG argues that the Company's commercial forecasting model assumes inordinately high vacancy rates in the office sector (CONUG Initial Brief at 27). CONUG contends that high vacancy rates reduce energy usage because vacant space uses only approximately 20 percent of the electricity of occupied space (id.). CONUG submits that a study of current office vacancy rates conducted by Meredith and Grew identifies an overall office vacancy rate for the greater Boston market of twelve percent (id. at 28). CONUG argues that the impact on the 1994 commercial forecast of assuming a twelve percent vacancy rate, rather than the 23 percent figure used by the Company would be to raise the 1994 peak load forecast by 30 MW (id.).

CONUG argues that the Company's commercial forecast model is also flawed because of its failure to incorporate some measure of commercial output (id.). CONUG contends that using commercial employment rather than commercial output as a variable in the commercial energy forecast results in an understated and less reliable forecast (id.). CONUG asserts that regression analysis shows that commercial output is a stronger predictor of commercial energy sales than commercial employment (id.). In addition, CONUG contends that a forecast of commercial sales based on regression analysis that uses commercial output as the independent variable would result in a higher sales forecast than one based on regression analysis using commercial employment as the independent variable (id. at 29).

As discussed in Section II.B.1, above, CONUG argues that the Company's commercial energy forecast understates non-manufacturing employment, resulting in unreliably low projections of commercial energy sales and peak load.

ii. <u>The Company</u>

In response to CONUG's arguments regarding office vacancy rates, the Company contends that there exist numerous vacancy rate forecasts, and that those forecasts are often at variance with one another (BECo Reply Brief at 27). The Company argues that, because the CEDMS model is calibrated to energy consumption in a base year, the level of vacancy rates in the base year has a far less significant impact on the energy forecast than the rate of change in vacancy rates in successive years of the forecast (<u>id.</u> at 27, 28). BECo contends that CONUG's argument regarding the impact on peak load of adjusting the base year vacancy rate is, therefore, not valid (<u>id.</u> at 27).

With respect to CONUG's argument that commercial output is a better predictor of commercial energy sales than commercial employment, the Company responds that commercial employment is only one of several factors that affect commercial sales (<u>id.</u> at 28). BECo argues that commercial sector demand for electricity is a function of the saturation of equipment, electric use intensity of that equipment, and the rate of utilization of that equipment (<u>id.</u>). The Company asserts that it is not possible to model the effects of these factors through a single variable such as commercial output (<u>id.</u>).

c. Analysis and Findings

The Department has reviewed the Company's commercial energy forecasting methodology and notes that it is consistent with Department precedent. See 1992 BECo Decision at 73. In the past, the Siting Council approved a commercial energy forecasting methodology that included disaggregation by building type and end-use, and accounting for the interactive aspects of many of the factors contributing to commercial energy consumption. Id. The Company's commercial energy forecast methodology in the instant case includes disaggregation of commercial energy consumption by twelve building types and eight end-uses. Additionally, the Company's commercial energy forecast model accounts for the interactive aspects of a number of factors that contribute to commercial energy consumption, including the level of economic activity, relative fuel prices, equipment capital costs, and standards for commercial square-footage-per-employee.

The record in this case indicates that BECo's commercial energy forecasting model incorporates projections over time of office vacancy rates based on data supplied by F.W. Dodge. The record in this case further indicates that the Company recalibrated the CEDMS model in 1993. The Department finds that, as long as base year energy consumption is reasonably well-calibrated to a base year vacancy rate level, the change in vacancy rates over time will be more critical to reliable forecasting than the absolute level of base year vacancy rates. Therefore, for the purposes of this review, the Department finds the Company's use of the F.W. Dodge vacancy rate data for 1994 to be acceptable.

In examining CONUG's contention that the Company should use a measure of output instead of a measure of employment in its commercial energy sales forecast, the Department reviews how employment data is actually used in BECo's commercial energy forecast. The record in this case indicates that BECo's commercial energy forecasting model used non-manufacturing employment as a proxy for commercial floorspace. Commercial employment levels were not used directly to predict commercial sales. Instead, the Company modelled commercial sales as a function of commercial floorspace, equipment energy use intensities, and equipment utilization rates. In the context of this examination of the CEDMS model, the Department finds CONUG's argument that commercial output is a better predictor of commercial sales than commercial employment to be non-critical.

The Company's projection of the level of non-manufacturing employment in the BECo service territory was used as a proxy for commercial floorspace, and thus constitutes a key driver of the Company's commercial energy and peak load forecasts. The record in this case indicates that the Company's commercial energy forecast is based on employment data from DRI's February 1994 forecast of the Massachusetts economy. The August 1994 DRI forecast reflects a substantial upward revision to the previous forecast of Massachusetts non-manufacturing employment. The record further indicates that a rebenchmarking or revision of historical employment data may account for the difference between projected non-manufacturing employment in DRI's February 1994 and August 1994 forecasts. Therefore, the Department finds that the higher levels of non-manufacturing employment projected in the DRI's August 1994 forecast would not necessarily result in projections of higher levels of commercial energy sales and commercial peak load.

However, as discussed previously, the Company did not provide any sensitivity analysis of its commercial energy forecast. Such an analysis might have demonstrated the responsiveness of the Company's commercial energy sales and commercial peak load forecasts to changes in the levels of historical and forecasted non-manufacturing employment. Absent a sensitivity analysis, it is difficult for the Department to assess the degree to which changes in non-manufacturing employment might affect the Company's commercial energy forecast. Moreover, while there might be a noticeable effect as a consequence of changes to this single input factor, other changes in forecast input values evidenced in DRI's August 1994 forecast might counteract the effect of the change in non-manufacturing employment. Therefore, while the Department finds some cause for concern that the commercial energy forecast may tend toward a downward bias, the Department finds that inputs to the forecast fall within a reasonable range.

Accordingly, the Department finds, for the purposes of this review, that the Company's commercial energy forecast is reviewable, but only minimally appropriate and minimally reliable.

6. <u>Industrial Energy Forecast</u>

a. <u>The Company's Proposal</u>

BECo projected industrial energy consumption to grow from 1,584 GWH in 1994 to 1,810 GWH in 2004, a compound annual growth rate of 1.34 percent (Exh. BE-1, Book 1, at A.1-3 Update). The Company indicated that the methodology used to produce its industrial energy forecast was similar to that which was used in the previous forecast (Exh. BE-1, Book 2, at F.A-40).

The Company forecasted total industrial energy consumption as the sum of sales in 19 Standard Industrial Classification ("SIC") code groups (id. at 41).[25] BECo indicated that its industrial energy forecasting model, which it referred to as the "Factor Decomposition Model," was based on the assumption that energy sales to industrial customers within a particular SIC group were a function of growth in industrial output and the intensity of manufacturers' energy use (id. at 40). Therefore, the Company asserted that annual change in energy sales to a particular SIC group could be forecasted by projecting the rates of change in industrial output and energy intensity (id. at 40, 41).

The Company stated that, because of a lack of industry- and territory-specific data pertaining to industrial energy consumption, development of the Factor Decomposition Model involved a two-phase process (id. at 41). The first phase of the model's development entailed compiling and analyzing macro-level variables, including DRI's forecasts of Massachusetts gross state product and Massachusetts employment, the Company's forecasts of employment and electricity price, and weather data (id. at 43-47). The Company stated that the second phase of the model's development entailed compiling and analyzing micro-level data, including building and equipment stock estimates (id. at 47).[26]

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[25] The 19 SIC groups were food and kindred products (SIC 20), textile mills (22), apparel products (23), lumber and wood (24), furniture and fixtures (25), pulp and paper (26), printing and publishing (27), chemicals (28), petroleum products (29), rubber and plastics (30), leather products (31), stone, clay, and glass (32), primary metals (33), fabricated metals (34), non-electric machinery (35), electrical machinery (36), transportation equipment (37), instruments (38), and miscellaneous (39) (Exh. BE-1, Book 2, at F.A-45-46).

[26] The Company indicated that it has been in the process of developing micro-level data (continued...)

To develop projections of rates of change in industrial output, the Company first calculated a measure of productivity using gross state product and state employment data (id.). The productivity measure and information from the territory employment forecast were combined to produce a measure of BECo territory output (id.). Changes in territory output over time yielded an index of change in territory output (id.).

The Company used regression analysis to develop projections of rates of change in energy use intensity (id. at 42). Inputs to the Company's regression equations included variables characterizing the level of economic activity, such as territory employment, gross territory product, and a Massachusetts industrial production index (id. at 43). These variables were used as proxies in the regression equations for the level of electric technology development (id.). In addition, the regression equations included terms pertaining to electricity price and weather (id.). The Company indicated that it performed statistical tests to establish the validity of its energy use intensity equations (id.).[27]

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[26](...continued)
since 1990 (Exh. BE-1, Book 2, at F.A-41). The Company added that it has acquired such data through responses to an initial (1990) survey of BECo commercial and industrial customers (id.). BECo indicated that the responses to the initial survey did not provide statistically significant results, but that they were nonetheless used for the purposes of the forecast in the instant case (id.). The Company stated that another survey is currently underway, and that it expects that the combined results of the two surveys will yield better results (id.).

[27] The Company indicated that regression equations for food and kindred products (SIC 20), lumber and wood (SIC 24), printing and publishing (SIC 27), petroleum products (SIC 29), and miscellaneous (SIC 39) produced poor statistical results (Exh. BE-1, Book 2, at F.A-45-46). The remaining 14 equations produced an R-squared of 0.69 or above (id.).

b. Analysis and Findings[28]

The Company's industrial energy forecast exhibits several notable strengths. First, the Company disaggregates industrial energy consumption into 19 separate SIC groups. In addition, the Company's Factor Decomposition Model is based on the sound assumptions that changes in industrial energy consumption are closely tied to changes in industrial output and energy use intensity. Further, the Company has attempted to incorporate territory-specific information regarding use of industrial equipment. In the past, the Siting Council approved an industrial energy forecast based on a methodology similar to that employed by the Company in the instant case. See 1992 BECo Decision at 83.

The Company's industrial forecast exhibits some weaknesses that appear to be based primarily on the Company's lack of success in obtaining statistically significant survey results. First, some of the Company's regression equations used to project industrial energy use intensities did not perform well statistically. In addition, the Company used economic data as proxies for electric technology development at industrial firms in the BECo service territory. Therefore, upon balancing the strengths and weaknesses noted above, the Department finds that the Company's industrial energy forecast is reviewable, appropriate, but only minimally reliable.

The Department recognizes that, because of the limited number of industrial firms in the BECo service territory, the lack of uniform production processes among those firms, and rapidly changing economic circumstances, obtaining reliable, territory-specific data pertaining

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28 No party submitted comments regarding the Company's industrial forecast methodology.

to use of energy in the industrial sector can be highly problematic. The Department further recognizes that the Company is continuing to attempt to develop reliable industrial survey data. However, the Department is concerned that the problems currently exhibited by the Company's industrial energy forecast have persisted for some time. The Company should continue its efforts to rectify these problems.

7. Miscellaneous Energy Forecast

i. The Company's Proposal

In addition to forecasting energy consumption in the residential, commercial and industrial sectors, BECo projected energy consumption for the following classes: streetlighting, municipal sales, the Massachusetts Bay Transit Authority ("MBTA"), and the Massachusetts Water Resources Authority ("MWRA") (Exh. BE-1, Book 2, at F.A-48 to 50). The Company indicated that it projected energy sales to these classes to grow from 161 MW in 1994 to 243 MW in 2004, a compound annual growth rate of 4.20 percent (Exh. BE-1, Book 1, at A.1-5 Update).

BECo stated that the streetlighting forecast was derived by projecting (1) the number and types of streetlighting bulbs in the service territory, and (2) the energy use associated with incandescent bulbs, mercury bulbs and sodium vapor bulbs (Exh. BE-1, Book 2, at F.A-48). The Company stated that the number of streetlighting bulbs in the service territory was determined by assuming (1) the rates of conversion from incandescent bulbs to mercury bulbs for the years 1993 through 2003 based on the average rate of conversion from incandescent bulbs to mercury bulbs in the service territory for the years 1990 through 1992, and (2) conversion from mercury bulbs to sodium vapor bulbs for the years 1993 through

2003 based on the average rate of conversion from mercury bulbs to sodium vapor bulbs in the service territory for the years 1990 through 1992 (id.). The Company stated that it assumed no additional conversions would occur after 2003 (id.). The Company stated that it used internal data to develop estimates of annual energy usage per bulb for each bulb-type (id.).

The Company indicated that it planned to make annual energy sales throughout the forecast period to the municipalities of Concord, Wellesley, Braintree, and Reading (id. at 48 to 49). The Company used regression analysis to forecast energy sales to the Towns of Concord and Wellesley (id. at 48). Sales to these towns were forecasted assuming that their energy requirements would depend upon levels of gross domestic product, personal income, and the number of people employed in the respective municipalities (id.). Town employment forecasts were developed by applying territory employment growth rates to actual 1992 town employment (id.). Projections of gross domestic product and personal income were obtained from DRI (id.). The Company stated that the forecasts of sales to the Towns of Braintree and Reading were based on information supplied by those municipalities (id. at 49).

BECo stated that projected sales to the MBTA were based on a new contract making BECo the sole power supplier for the MBTA (id.). Similarly, sales to the MWRA were based on a contract for energy usage by the MWRA's Deer Island Facility (id.).

a. Analysis and Findings

The record demonstrates that BECo's miscellaneous energy forecast is based on (1) a reasonable set of methodological assumptions, and (2) data from reliable sources. However, with respect to the Company's forecasts of sales to municipalities and state agencies, the

Department notes that the Company did not submit information regarding the contractual provisions that determine the level of these sales. Based on the foregoing, the Department finds that the Company's miscellaneous energy forecast is reviewable, appropriate, and reliable. However, in order for the Department to approve the miscellaneous forecast in the Company's next filing, the Company must furnish documentation of the contractual provisions relevant to the projected level of sales to municipalities, state agencies, and any other wholesale customers.

8. Conclusions on the Energy Forecast

The Department has found the Company's employment, electricity price, residential energy sales and commercial energy sales forecasts to be reviewable, minimally appropriate and minimally reliable. Further, the Department has found the Company's demographic forecast and miscellaneous energy sales forecasts to be reviewable, appropriate and reliable. In addition, the Department has found the Company's industrial energy sales forecast to be reviewable, appropriate and minimally reliable. On balance, the Department finds the Company's energy forecast to be reviewable, minimally appropriate and minimally reliable.

C. Peak Load Forecast

1. The Company's Proposal

The Company stated that in 1993 it was a summer peaking system, and that it expected to remain so throughout the forecast period (Exh. BE-1, Book 1, C-1 update, C-2 update). The Company forecasted its summer peak load to grow from 2,707 MW in

1994 to 3,028 MW in 2004, a compound annual growth rate of 1.13 percent.[29] The Company forecasted its winter peak to grow from 2,463 MW in the winter of 1994-1995 to 2,802 MW in the winter of 2003-2004, a compound annual growth rate of 1.30 percent (id.).

The Company indicated that it used the Electric Power Research Institute's Hourly Electric Load Model ("HELM") to forecast peak load (Exh. BE-1, Book 2, at F.A.-51). The Company stated that HELM used territory-specific end-use load data from the Company's load research files and the results of the energy forecasts to produce the territory summer and winter peak load forecasts (id.). The Company indicated that hourly load shapes by class and end-use for each of five day-types within each of three seasons were incorporated into the HELM data set (id.).[30] The Company stated that historical data used in the peak load model reflected a base year of 1990 (id.).

The Company indicated that the hourly load profiles were combined with the Company's energy forecast by end-use and sector (id. at 52). Annual end-use energy for the residential and commercial sectors was divided into season, day-type, and hour according to the load profiles (id). A residual, miscellaneous category was developed to account for all energy sales not reflected in one of the load shapes that was explicitly modelled (id.).

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[29] The actual 1994 summer peak load experienced by the Company was 2,832 MW (Exh. CON 1-10).

[30] BECo indicated that the five day-types modelled by HELM were (1) weekends, (2) holidays, (3) weekdays, (4) highdays representing the 14 days of the highest demand after the peak day in a given season, and (5) peak day (Exh. BE-1, Book 2, at F.A.-51). The three seasons modelled by HELM were (1) summer (June through September), (2) winter (January, February, March, and December), and (3) Spring/Fall (April, May, October, and November) (id.).

HELM-estimated residential and commercial peak loads were then calibrated to actual seasonal peak loads from 1990, and all other hours for the forecast period were calculated by the model based on the level of projected energy sales (id.). The Company indicated that annual energy for the remaining sectors was allocated into seasons, day-types and hours according to the relative hourly loads of each of the day-types in 1990 (id.). The hourly peak loads across all sectors were added together to derive total company-wide seasonal peak loads at the customer level (id.). Average transmission and distribution losses associated with each sector were added to customer level peak loads to derive BECo seasonal peak loads at the generator level (id.).

The Company stated that the high temperature on days of summer peak has averaged 95 degrees fahrenheit across recent years (id.). BECo indicated that the high temperature on the summer peak day of 1990, the base year of its model, was 93 degrees. BECo indicated that it conducted regression analysis to establish that a one degree variation in summer peak day temperature corresponds to a 47.5 MW variation in peak load (id.). The base-year summer peak load in the model was therefore adjusted upward by 95 MW to reflect anticipated peak loads consistent with average summer peak day temperatures (i.e., 95 degrees) (id.). The base year adjustment of 95 MW was increased in successive years according to the rate of growth in air conditioning end-uses (id.). The Company stated that the base-year winter peak was adjusted in a like manner to reflect loads that could be anticipated on an average winter peak day (id.).

As noted previously, the actual 1994 summer peak load experienced by the Company was 2,832 MW (Exh. CON-1-10). The actual peak load was 125 MW higher than the forecasted peak load of 2,707 MW (Exh. BE-1, Book 1 at C-1 update). The Company stated that the maximum temperature on the day of the 1994 summer peak load was 97 degrees, two degrees higher than the maximum temperature anticipated in its peak load model (Exh. BE-5 at 12). The Company asserted that a comparison of the actual peak load to the forecasted peak load would require that a weather adjustment be made to the actual peak load to account for the difference between the predicted maximum temperature on the day of peak and the actual maximum temperature on the day of peak (id.). The Company further asserted that for every one degree deviation from average maximum temperature on the day of peak, there is a 50 MW impact on load (id.; Exh. CON-4-4). The Company provided information indicating that the maximum temperature in Boston has exceeded 95 degrees on 48 days since June 11, 1973 (Exh. CON-4-3).

2. Positions of the Parties

a. CLF/MASSPIRG

CLF/MASSPIRG contend that the Company has overstated peak load because it has not accommodated the federally-mandated schedule to increase equipment efficiency and building codes standards (CLF/MASSPIRG Joint Reply Brief at 14-15). CLF/MASSPIRG argue that the National Energy Policy Act of 1992 and the National Appliance Energy Conservation Act of 1987 establish schedules for upgrades of appliance efficiency standards and model building codes (id.). CLF/MASSPIRG add that the Company's demand forecast only accounts for the standards that have already been adopted (id.).

b. CONUG

CONUG asserts that the Company's peak load forecast demonstrably understates peak load growth (CONUG Initial Brief at 19). CONUG further asserts that the Company's peak load forecast does not meet the Department's standard that a forecast must be reliable (id.). Supporting its assertion that the Company's forecast is not reliable, CONUG states that the actual summer 1994 peak load was 125 MW higher than the peak load that was predicted in the forecast (id. at 21).

CONUG opposes the Company's claim that the 1994 summer peak load underforecast was due to abnormal weather conditions. CONUG contends that the weather conditions on the summer peak day in 1994 were not extraordinary, and that they may be expected to re-occur regularly during the forecast period (id. at 21-22). CONUG argues that the Company's underforecast of the 1994 summer peak load is attributable to (1) an understatement of the number of non-manufacturing jobs in Massachusetts in 1993 and 1994, (2) an overstatement of office vacancy rates, (3) a failure to incorporate a measure of commercial output in the commercial energy forecast, and (4) an understatement of residential sector room air conditioner saturations (see above) (id. at 25-30).

c. The Company

The Company argues that its peak load forecasting methodology is well-documented, and virtually the same as methodologies previously approved by the Siting Council (BECo Reply Brief at 17). With respect to the 1994 summer peak load, the Company asserts that, when one performs a weather adjustment for the actual 1994 summer peak load, the result is consistent with the Company's demand forecast (id. at 23). In addition, the Company argues that its adjustment of 50 MW for each degree above 95 degrees on the day of summer peak is appropriate (id. at 24).

3. Analysis and Findings

The Company's peak load forecast methodology exhibits several strengths. BECo's peak load forecast is disaggregated by end-use and class. The forecast allocates energy consumption on an hourly basis, and accounts for the effects of day-type and season. The Company's peak load forecast methodology also includes adjustments to account for the effects of weather and the Company's DSM programs. In addition, BECo's peak load forecast incorporates load profiles based on territory-specific load research data.

Nonetheless, the record in this case gives rise to a number of significant concerns regarding the Company's peak load forecast. First, despite the strengths noted above, the record demonstrates that the Company significantly underforecasted the 1994 summer peak load. The underforecast is of particular concern because the first year of a forecast period should be the easiest to predict accurately and because any error not attributable to weather conditions would in likelihood be compounded across the forecast period. While weather conditions on the day of the 1994 summer peak load may account for some of the underforecast, the record in this case indicates that weather conditions on that day were not uncommon. The Department is therefore concerned that the Company's forecast will understate peak load in subsequent years of the forecast period to the extent that similar weather conditions recur, which does not appear unlikely.

A second concern with the Company's peak load forecast entails the undercounting of the number of residential room air conditioners in BECo's service territory. The record in this case indicates that this undercounting resulted in the energy consumption from room air conditioners being reallocated to the miscellaneous residential energy category. However, the record in this case indicates that differential amounts of energy consumption of residential room air conditioners can be expected to have a far more significant impact on the Company's summer peak than an equivalent amount of energy consumption in the miscellaneous residential category. Therefore, the Department finds that BECo's reallocation is likely to put downward pressure on the peak load forecast.

A third challenge to the reliability of BECo's peak load forecast may result if appliance efficiency and model building code standards are adopted that would reduce the levels of load growth that would otherwise occur. The record demonstrates that the Company did not address the possibility of future, more rigorous, federally-mandated efficiency standards. While the level and timing of future efficiency standards remain highly uncertain at this time, new standards could challenge the accuracy of the peak load forecast--although in a direction that might tend to balance the results of other factors addressed here.

Finally, the Department notes that the Company did not provide sensitivity analyses to demonstrate the responsiveness of the peak load forecast to changes in key inputs to the energy and peak load forecasts. The record demonstrates that there exists considerable uncertainty with respect to many factors that underlie the peak load forecast, including levels of employment, population, electricity and fossil fuel prices, efficiency of energy-consuming equipment, and penetration and effectiveness of Company-sponsored DSM programs and measures. The record further demonstrates that the Company conducted scenario analyses in an attempt to address some of these, as well as other uncertainties (see below). However, the Company's demand-side scenario analyses entailed direct adjustments to the of numbers of customers and average-energy-use-per-customer. While this approach may have considerable planning value, it cannot provide insights into the interactions and relationships between key drivers of the Company's energy and peak load demand forecasts and the results of those forecasts. Therefore, the Department finds that the scenario analyses, as applied by the Company, are of only limited usefulness in assessing the reliability of the Company's peak load forecast. The IRM regulations require that a company's "demand forecast shall include sensitivity analyses of major assumptions contained in an electric company's forecast methodology." See 220 C.M.R § 10.03(6)(e). The Department finds that the Company has not clearly demonstrated that its use of scenario analysis is an acceptable substitute for sensitivity analysis to demonstrate the responsiveness of the peak load forecast to changes in projected levels of key forecast inputs. Instead, scenario analysis can serve as a useful complement to a rigorous sensitivity analysis.

Based on the strengths and weaknesses of the Company's forecast methodology discussed above, the Department finds that the Company's peak load forecast is reviewable, minimally appropriate, and minimally reliable.

D. Conclusions on the Demand Forecast

The Department has found the Company's energy forecast to be reviewable, minimally appropriate, and minimally reliable. In addition, the Department has found the Company's peak load forecast to be reviewable, minimally appropriate, and minimally reliable. Accordingly, the Department accepts the Company's 1994 demand forecast.

However, due to concerns raised regarding the underforecast of the summer, 1994 peak load, increases in the level of non-manufacturing employment reflected in the August 1994 DRI forecast, and the lack of sensitivity analyses as required by the IRM regulations, the Company is directed to submit an intercycle forecast, as required by provisions of 220 C.M.R. § 10.07(4) on January 2, 1996. Such intercycle forecast filing shall include, but not be limited to, (1) full documentation of any changes to the methodologies reviewed in the instant case, (2) citation of the source and vintage of all data inputs used in the intercycle forecast, and (3) compliance with each of the directives contained herein.

III. THE RESOURCE INVENTORY

A. Introduction

The IRM regulations set out the specific filing requirements for an electric company's resource inventory. 220 C.M.R. § 10.03(7). They establish that an electric company must identify, in its initial filing, the inventory of existing and planned resources that it will have available to respond to system demands during the forecast period. 220 C.M.R. § 10.03(7)(a). In particular, the IRM regulations require an electric company to identify separately (1) existing supply-side resources, (2) existing DSM resources, (3) planned supply-side resources, and (4) planned DSM resources. 220 C.M.R. § 10.03(7)(b). The IRM regulations also require that all existing and planned resources be included in the resource inventory submitted to the Department with the exception of (1) those units that, due to extraordinary circumstances, are excluded by the Department from an electric company's resource inventory, and (2) those electric company-owned units that the electric company demonstrates should be excluded from its resource inventory. 220 C.M.R. § 10.03(7)(a). The Department reviews an electric company's filing to determine whether all existing and planned resources have been properly included in the resource inventory. Id.

B. Inventory of Existing Supply-Side Resources

1. Introduction

The IRM regulations define existing supply-side resources as those resources that either (1) have been providing kilowatts or kilowatthours to an electric company at some time within the year beginning 13 months and ending one month before the submission of the initial filing, or (2) have provided kilowatts or kilowatthours to the electric company at some time prior to 13 months before the submission of the initial filing, and can be made operational without approval from the Department. 220 C.M.R. § 10.02. The IRM regulations require that the performance of existing resources be reviewed to determine whether each unit's performance has been evaluated appropriately in the filing. 220 C.M.R. § 10.03(7)(a).

In addition, in D.P.U. 93-112-A the Department established cost recovery and planning standards with respect to expenditures made at existing units in response to requirements related to the Clean Air Act Amendments of 1990 ("CAAA"). The Department stated that expenditures could be deemed prudently incurred only if such expenditures were found to be consistent with "a least-cost compliance strategy that reflects comprehensive consideration of all reasonably foreseeable costs ... (including those associated with all known and likely CAAA and other environmental regulation requirements) as compared with the costs of reasonable alternatives." D.P.U. 93-112-A at 17. In that Order, the Department further established IRM filing and review requirements related to an electric company's strategy for achieving least-cost compliance with the requirements of the CAAA. First, the Department determined that

> [w]hether extraordinary circumstances arise that make it appropriate to exclude an existing resource from a company's initial resource portfolio because of projected expenditures for CAAA compliance, and to test the continued operation of that resource in the market of alternative investments through an IRM resource solicitation, will be evaluated within the context of upcoming IRM proceedings.

Id. at 16. In order to expedite the IRM evaluation noted above, the Department established that IRM filing requirements for units affected by the CAAA shall include

> up-to-date compliance information concerning all known and potential compliance requirements, including those related to the control of hazardous air pollutants, and shall include a demonstration that all requirements and all options for compliance have been considered in developing a least-cost compliance plan.

Id. at 17-18.

2. The Company's Proposal

Existing supply-side resources owned by the Company include the following units: Pilgrim, New Boston 1 and 2, Mystic 4, 5, 6, and 7, and approximately 215 MW (summer) of generating capacity from fifteen combustion turbines (Exh. BE-1, at Table B.2-1, rev01). Units that contribute to current and future generating capacity from joint-ownership with, or long-term purchases from, other utilities include Wyman 4, Connecticut Yankee, Canal 1, and Bear Swamp (id.). Resources purchased through agreements with nonutility generators include Ocean State Power 1 and 2, NEA 1 and 2, L'Energia, MassPower, and MBTA combustion turbines 1 and 2 (id.). The Company identified its MW entitlements in each existing supply-side resource over the planning horizon (id.).

The Company has also included in its resource inventory a "capability credit" of 237 MW associated with NEPOOL's interconnection with the Hydro Quebec system. During the term of the firm energy contract between NEPOOL and Hydro Quebec, the NEPOOL Objective Capability ("OC") -- which is used to establish each NEPOOL member's capability responsibility ("CR") -- is adjusted to replace the tie-line benefit associated with the NEPOOL interconnection to the Hydro Quebec system with a capability credit.[31] The

[31] NEPOOL recognizes a reliability benefit associated with its transmission intertie to the Hydro Quebec system (before consideration of the effects of the firm energy contract with Hydro Quebec) of 1500 MW during summer months (Exhs. BE-7, Att. 2, at 1; CON-2-37, Att. 1, at 19). This "tie benefit" serves to reduce NEPOOL's objective capability, and thus the capability responsibilities reflecting resource levels that participants would otherwise have to make available to NEPOOL (Exhs. CON-2-37, Att. 1, at 13, 14, 17; CON-2-14, Att. 1, at 1-2). NEPOOL permits electric companies participating in the Hydro Quebec Firm Energy Contract to treat their respective shares in that contract as a credit toward capability responsibility that reduces the level of resources that they must make available to NEPOOL (Exh. CON-2-14, Att. 1, at 6). To determine the amounts of the credits, NEPOOL first models the Firm Energy Contract as a "proxy" generating units with a summer capacity of 1800 MW (Exh. CON-2-37, at 19). This total "interconnection credit" amount is divided among contract participants according to their relative shares in the contract (Exh. AG-2-8, at 3). So as not to "double count" the reliability benefits that derive from the tie the Hydro Quebec system (i.e., the "tie benefit" and the "interconnection credit" both serve to reduce the capability responsibilities of those participating in the Firm Energy Contract), NEPOOL calculates an "adjusted capability responsibility" by adding the total "interconnection credit" amount to the objective capability (Exh. CON-2-37, Att. 1, at 19-20). The adjusted objective capability and the "final" participant capability responsibilities (which are based on adjusted objective capability) are thus increased, thereby eliminating any inappropriate double counting of Hydro Quebec reliability benefits (Exh. CON-2-14, Att. 1, at 2). The MW value of the capability credit is derived by replacing the tie-line benefit representation of the Firm Energy Contract (1500 MW) with generic or proxy units

(continued...)

adjustment increases OC (and, consequently, each member's CR) as the tie-line benefit is removed, but the capability credit benefit associated with the contract is transferred to each member as an interconnection capability credit (Exh. BE-7, Att. 2, at 1).

The Company has proposed to base projections of unit equivalent availability factors ("EAF")[32] on performance targets established by the Company's fossil and nuclear operations divisions (Exh. BE-7, Att. 4). The Company states that a projected improvement of the reliability of its generating units is a major contributor to the projected decrease in the Company's NEPOOL reserve margin, from 18 percent in 1993 to 13 percent in 2004, which represents a savings of approximately 150 MW (Exh. BE-7, Att. 3).

3. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Company's forecasts are based on base case assumptions of generating unit life expectancies and performance that are overly optimistic as base case assumptions (Attorney General Brief at 12). The Attorney General states that the Company's overly optimistic assumptions include (1) the remaining life and projected capacity factor increases for Pilgrim; (2) the increase in average equivalent availability factor

[31](...continued)
until the NEPOOL system has the same reliability with the proxy units as with the tie-line benefit representation (Exh. BE-7, Attachment 2 at 1; Exh. CON-2-37, Attachment 1 at 19). This results in an interconnection capability credit of 1800 MW (id.). BECo's share of this capability credit is 237 MW.

[32] The equivalent availability factor of a unit is the fraction of maximum generation that a unit would be able to produce if limited only by outages and deratings. See, Boston Edison Company, D.P.U. 91-1A-1, at 5 (1992).

of the Company's fossil units; (3) the cost and availability of operating the New Boston units on gas after 1995; and (4) the overall reduction of the Company's reserve requirements due to improved EAFs (id.). The Attorney General states that, where the Company's base case assumptions are overly optimistic, system costs will be understated such that the utility may forego cost-effective resource alternatives, while passing the risk of increased costs on to ratepayers (id.). The Attorney General asserts that, since the Company refuses to extend the use of its unit performance assumptions for the purpose of establishing performance goals in the generating unit performance program administered by the Department,[33] the Company's IRM base case resource plan exposes ratepayers, but not shareholders, to financial risk (id. at 13).

b. CONUG

CONUG's comments on the Company's existing supply-side inventory focus on three areas: (1) the effect of the Company's assumptions concerning unit performance on necessary reserve margins; (2) resources that should be excluded from the resource inventory; and (3) reliability uncertainties associated with existing units. Each of these areas is addressed below.

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[33] In accordance with G.L. c. 164, § 94G, the Department conducts annual performance review proceedings where in actual unit performance is compared with performance goals set in a prior goal-setting proceeding. Should the Department determine that a company has failed to meet performance goals as a result of unreasonable action or imprudence, the Department shall disallow the resultant costs.

i. <u>Generating Unit Performance</u>

CONUG contends that the Siting Council precedent regarding unit availability may be described as a rebuttable presumption that availability should be based on historical experience, and that the Company has taken actions that are likely to result in a decrease, rather than an increase, in future EAFs (CONUG Reply Brief at 27). CONUG thus asserts that the Company has failed to meet its burden to establish that its assumptions concerning the performance of its existing units are appropriate, and argues that in calculating the Company's resource requirements the reserve margin should be adjusted upward to reflect the historical performance of these units (CONUG Brief at 53). CONUG notes that even the Company's estimates of a reserve margin assuming historical average EAFs (Exh. AG-2-24) inappropriately assumed (1) that the Company's non-utility generator ("NUG") units will have an availability of 90 percent, which is significantly higher than the 81.4 percent availability target that NEPOOL assigns to these units, and (2) that L'Energia will have an availability of 87 percent, despite the fact that its actual first year availability was 55.5 percent (CONUG Brief at 53-54). CONUG contends that the reserve margin should be further adjusted upward in consideration of these overestimates (<u>id.</u>). CONUG asserts that a reasonable alternative in the absence of historical operating experience for the NUG units is to assume that such units will operate at NEPOOL target unit availability levels (CONUG Reply Brief at 35).

ii. <u>Resources That Should Be Excluded From the Resource Inventory</u>

CONUG contends that the Company has inappropriately included in its resource inventory two resources that do not meet the criteria for either planned or existing resources (CONUG Brief at 55). First, CONUG asserts that Canal 1 should be eliminated from the Company's resource inventory as of the date of contract termination, and that the Company's witness testified that the contract would expire in July 2001 (CONUG Reply Brief at 37-38).

Second, CONUG questions the Company's treatment of Hydro Quebec in the Company's filing. CONUG contends that, prior to the year 2000, BECo's portion of the capability attributable to Hydro Quebec should be based on the overall NEPOOL value of 1500 MW, which is the value contained in the CELT report, rather than based on the NEPOOL value of 1800 MW as used in the Company's initial filing (<u>id.</u> at 56). Further, CONUG contends that the Company's treatment of Hydro-Quebec (1) should not include any capability credit beyond the end of the contract, and (2) overstates the tie-line reliability benefit of the interconnection with Hydro Quebec after the year 2000 (<u>id.</u>). CONUG concludes that Hydro Quebec must be removed from the Company's resource inventory after the year 2000, and any reduction in BECo's reserve margin after the year 2000 that may result from the Hydro Quebec tie should be limited to three percent (<u>id.</u> at 56-57).

iii. <u>Unit Reliability Attrition</u>

CONUG contends that there are a number of reliability uncertainties associated with the operation of existing units that BECo has not considered in assessing its resource inventory, including compliance with the CAAA, the availability of gas to New Boston

Station, the operation of Mystic 5, the reduction in availability of units during warm summer conditions, and the potential for premature retirement of Pilgrim (CONUG Brief at 66-74).

First, CONUG asserts that a significant portion of the Company's capacity has not yet achieved compliance with the applicable NO_x standards of the CAAA, and that the Company's combustion turbines may fail to do so ever (CONUG Brief at 69). CONUG notes that none of the Company's plans for the Mystic units to comply with the NO_x reasonably achievable control technology ("RACT") standard by May 1995 have received approval. CONUG further contends that Company testing at Mystic 5 and 6 show that these units currently are nearly out of compliance with that standard (id. at 69-70).

Further, CONUG asserts that every one of the Company's combustion turbines exceed the May 1995 standard for emissions of NO_x, and states that the Company acknowledged that there are no emission control options that BECo can use to bring these units into compliance (id. at 70). CONUG contends that the Company's compliance plans for these units – the use of emissions averaging or emission reduction credits – are dependent upon a number of pending regulatory actions and decisions that are uncertain and must all occur in the Company's favor if the combustion turbines are to continue to operate (id. at 70-73). CONUG concludes that some reduction in the resource inventory is necessary to reflect the probability that continued operation of the Company's combustion turbines is at serious risk (id. at 73).

In addition, CONUG asserts that on winter peak days the New Boston units will be unable to operate and thus will not be a reliable resource (CONUG Brief at 68). According to CONUG, this reliability risk stems from questions surrounding whether or not the units will be able to burn oil on winter peak days (id. at 67). CONUG contends that the unavailability of gas under winter peak conditions is "an expected result of the Company's flawed gas procurement strategy," and thus would not constitute an emergency situation as defined in the Consent Agreement concerning operation of New Boston 1 and 2. CONUG concludes that under such circumstances the units should be drastically derated by NEPOOL, and that such derating could result in an immediate need for incremental winter capacity to meet the Company's winter capability responsibility (id. at 67-68).

CONUG also contends that the Company's analysis reveals that BECo must choose between derating Mystic 5 by up to 46 MW between now and 2000, or suffer a 19 percent availability penalty (CONUG Brief at 68). CONUG asserts that the Company's 1986 life extension study concluded that, until boiler tube repairs are made at Mystic 5, it would have to operate with the restrictions identified above (id. at 47). CONUG states that the Company has delayed the necessary repairs until the year 2000. CONUG concludes that, unless a specific assumption is made to reduce the projected availability of Mystic 5, a derating of at least 25 MW is appropriate (id. at 68-69).

CONUG asserts that the record indicates that, historically, significant fossil unit deratings have occurred during weather conditions typical of summer peak conditions, and that such deratings can be expected in the future (CONUG Brief at 66-67, citing Exh. CON-2-23). CONUG concludes that the unavailability of this capacity at the time of summer peak impacts power supply reliability (id. at 67).

Finally, CONUG contends that the testimony sponsored by the Attorney General indicates that a premature retirement of Pilgrim is a reasonably likely contingency that must be considered in assessing BECo's need for additional resources (CONUG Brief at 73).

CONUG asserts that the combined uncertainties discussed above should be addressed in the base case need calculation through a "reliability attrition factor" of 100 MW beginning in 1998 (CONUG Brief at 73-74).

c. CLF

CLF states that BECo has failed to include in its base resource plan an assessment of the potential for incremental environmental regulations, and that such failure is not consistent Department policy as expressed in its decision in D.P.U. 93-112-A (CLF Brief at 26). CLF concludes that the Department should require the Company to conduct such an assessment and to diversify its resource plan to include non-polluting resources that may provide the least-cost response to potential future regulations (id.).

CLF notes that BECo's plans for compliance with the NO_x RACT requirements of the CAAA are based on several uncertain events (id. at 19). CLF states that compliance with these requirements at the Company's combustion turbine units is dependent upon the issuance by the Massachusetts Department of Environmental Protection ("DEP") and approval by the United States Environmental Protection Agency ("EPA") of emissions averaging or emissions trading regulations (id.). Further, CLF asserts that BECo has not considered the cost, or the effect on unit performance and availability, of additional NO_x requirements, despite the fact that such limits are clearly possible (id. at 20-21).

Further, CLF asserts that the Company has not assessed the potential impact on Company units that likely future requirements related to air toxics, small particulates, and carbon dioxide would have (id. at 21-25). CLF argues that the Company has instead opted to merely "wait and see" if any new regulations are promulgated, which CLF suggests is inconsistent with the Department's policy articulated in D.P.U. 93-112-A (id. at 18).

d. Company

The Company asserts that it has fully evaluated all available resources, and that the assumptions used by the Company regarding unit availability and reliability over the planning horizon are reasonable and supported by the record (Company Brief at 51). The Company argues that CONUG's analysis of the Company's reserve margin and unit availability assumptions is not supported by record evidence, and that CONUG has failed to articulate a reasonable basis for rejecting any portion of the Company's resource plan (Company Reply Brief at 33). Further, the Company contends that the alternative reserve margins proposed by CONUG contain no presentation of background assumptions, and are not supported by any evidence on the record (id. at 45).

The Company argues that the record in this case is contrary to the arguments made by CONUG and the Attorney General that BECo's projected EAFs for it's units are too optimistic and should be significantly reduced (id. at 46-63). The Company contends that the basis for its generating unit EAFs is fully supported by the record, and may be reasonably relied upon for the purposes of planning for future power supply needs (id. at 46). BECo's chief executive officer, Thomas May, testified that in order to stay competitive in the electric utility industry, the Company would need to increase the utilization of its existing capacity

(Tr. 1, at 10-11). In this context, Mr. May asserted that the Company had successfully integrated its IRM plans with its business plan (id. at 12). In addition, BECo asserts that its use of an 87 percent availability projection for L'Energia is appropriate given the information available to the Company and the reasonable expectations of L'Energia's performance (Company Reply Brief at 64).

The Company also rejects the position taken by CONUG with respect to the Canal 1 contract. In particular, the Company asserts that BECo's decision to include the Canal 1 contract in its resource inventory beyond expiration of the existing contract was correct because (1) the Company has carefully and reasonably considered the value of the Canal extension option, and (2) to remove it from the resource inventory and solicit replacement capacity would result in losing the opportunity to extend a cost-effective contract (Company Reply Brief at 65-66). Further, the Company contends that, pursuant to the contract, the expiration date is October 31, 2001 at the earliest (not July 1, 2000, as asserted by CONUG) (id. at 65, citing Exh. CON-2-4).

With respect to compliance with the CAAA, the Company contends that the arguments presented by CONUG and CLF are greatly overstated (Company Reply Brief at 105). BECo argues that there is no need to worry about the possibility that emission averaging regulations will not be issued by DEP since DEP has stated an intention to do so, and that in any case, the appropriate response given this concern would be to work closely with DEP to facilitate issuance of the regulations (id. at 105-106). Further, the Company asserts that BECo has not ignored potential future requirements, and that the record indicates a full awareness and consideration of each pollutant (id. at 107). The Company concludes that there is no basis for the conclusions of CLF and CONUG concerning environmental compliance issues (id.).

The Company also argues that CONUG's reliance on the 1986 Life Extension Study fails to reflect substantial changes which have occurred since the study, and which are planned for the future (Company Reply Brief at 51). In particular, the Company asserts that the record indicates that repairs on the Mystic units have specifically improved the reliability of those units (id. at 54). The Company concludes that, with respect to the Mystic units, CONUG has relied upon the Life Extension Study while ignoring the record in this case (id. at 52).

Concerning the availability of New Boston Station, BECo states that (1) the Company continues to negotiate to improve its gas supply to New Boston Station, and that the final arrangement likely will differ from the planning assumption in the IRM filing which does not include a full supply of firm gas; (2) NEPOOL does not require a 100 percent firm gas supply for the units to qualify for NEPOOL capability credits; (3) the units in any case will be free to operate during emergency conditions; and (4) if the Company were unsuccessful in retaining the full capability credit for the units, it could still purchase firm gas to support full operation of the units or make up any temporary loss of credit with a short term power purchase (id. at 78-79). The Company contends that CONUG's assertion that the Company would not be allowed to burn fuel oil during peak periods is mere speculation (id. at 79).

Finally, the Company contends that CONUG is wrong with each of the arguments made in connection with BECo's assumptions concerning Hydro Quebec (id. at 67). The Company asserts that the record makes it absolutely clear that 1800 MW, not 1500 MW, is the appropriate NEPOOL-wide value to use in assessing BECo's portion of the total capability value of the contract (id. at 68-69). In addition, the Company asserts that the record clearly demonstrates that it is appropriate to treat Hydro Quebec as a capability credit, and that CONUG's assertions to the contrary are without merit and should be rejected (id. at 71). The Company argues that its treatment of Hydro Quebec should be accepted by the Department (id. at 67).

4. Analysis and Findings

The Department herein reviews the three main substantive issues regarding the Company's existing resource inventory discussed by the parties in this case: (1) existing unit performance (EAFs); (2) units to be included in (or excluded from) the resource inventory; and (3) other unit reliability uncertainties.

a. Existing Unit Performance

A clear standard against which presentations of unit availability will be reviewed has been established in prior Department and Siting Council decisions. 1992 BECo Decision, at 257-258. In particular, the Siting Council stated that

> [i]f the resource requirements calculation is to reflect a realistic assessment of the Company's future needs, it is essential that the "unit availabilities" forecasts reflect realistic estimates of the contribution that can be anticipated from existing resources.

Id. at 257. The Siting Council concluded that the historical EAF level (or recent actual EAFs–that is, the average of EAFs over the last five years) is the best indicator of future performance of a generating unit, but allowed for presentations of alternative EAF projections where recent performance trends or recent capital improvements will affect future performance. Id. at 257-258. Such presentations must be supported by evidence that quantifies the estimated effect of such improvements. Id. at 258. The Department's reliance on historical performance is based on the premise that it is the best indicator of future performance. Consequently, a company must present substantial quantitative support for deviations from this precedent.

With respect to BECo's reliability planning in this proceeding, the Department has substantial concerns regarding the projected EAFs presented by the Company. BECo has relied almost entirely on its plans to implement "management objectives" as the basis for increasing the availability of its existing units. However, the record does not provide empirical or other verifiable support for the Company's assertion that its overall management strategy will allow for a decrease in time for planned outages and maintenance without any impact on unit operating performance. Further, the record shows that performance at Pilgrim in the last two years is below the average over the last five years, in contrast to the Company's projection of strong improvement in Pilgrim's performance over the forecast period (RR-DPU-58). Thus the Department is not yet convinced that the Company's projection of generating unit EAFs are an improvement over the use of historical averages. The Department therefore finds that the Company's presentation has failed to provide sufficient quantitative support to abandon reliance on recent actual performance for the purposes of recognizing the contribution of existing and planned resources in meeting identified demand in this proceeding.

Additionally, the Department notes the Attorney General's proposal to link the proposed EAFs to the Company's performance program. As emphasized by the Company, in an increasingly competitive environment it is important to link its resource planning process with its business planning process. This suggests that an electric company's business plan and the integrated resource plan upon which resource decisions are based must be in concert in seeking to optimize the output of existing resources. Doing so will place an electric company in a better position to serve its customers and meet competitive pressures. The Department finds that linking EAFs used for planning purposes with those adopted for the purpose of Company performance reviews would further enhance the process of merging business and resource planning. The Department will investigate this matter in the Company's next goals filing. Consequently, in that filing the Company should present a generating unit performance incentive plan that utilizes EAF targets that are consistent with the EAFs that the Company would propose for resource planning purposes. The Department will evaluate these performance incentives consistent with the Order in D.P.U. 94-158, the Department's investigation into electric company incentives, which will be issued in 1995.

Finally, CONUG has challenged the assumptions used by the Company for the performance of non-utility generator units as overly optimistic, and has asserted that the Company's reserve margin should be adjusted upward as a consequence. The Department notes that almost none of the NUG units in the Company's existing resource portfolio have been in service long enough to establish a reliable historic average, yet it is important that the Company make some assumptions regarding the performance of these units over the planning horizon. Further, the Department finds that the record does not provide any calculations or estimates to support a reserve margin adjustment as recommended by CONUG. Therefore, the Department finds the Company's treatment of NUG unit EAFs reasonable for the purposes of assessing the contribution from existing resources in this proceeding. However, in its next filing the Company should present an assessment of recent actual performance for NUG units with BECo contracts and explain any deviations made in projecting EAFs for individual units.

In summary, the Department finds that, for the purpose of the resource need calculation, projections for existing unit performance shall be based upon recent actual EAFs (i.e., historical (five year) average) for company units, and BECo's projection of performance for NUG units in BECo's resource inventory. See Section IV, below.

b. Existing Units Included in the Resource Inventory

In this section the Department addresses resource inventory matters related to the inclusion of Canal 1 and Hydro Quebec after termination of those contracts. A competitive framework was established in the IRM regulations with the expectation that competitive procurement to meet an identified need was likely to result in least-cost resources for ratepayers. See D.P.U. 89-239, at 1-5 (1990); D.P.U. 86-36-F at 37-48 (1988).

With respect to Canal 1, the Company has asserted that a contract extension would likely be a very good deal for ratepayers. However, any presentation to the Department in support of cost recovery for Canal 1 costs under a contract extension would require a rigorous showing that the extended contract would be cost-effective compared to market alternatives, as would occur by including the unit in the initial resource portfolio in an IRM solicitation. See 220 C.M.R. §§ 9.00 et seq. Moreover, the Department notes that, if extension of the Canal 1 contract is in the best interest of ratepayers, it is likely to succeed in any solicitation held to meet an identified need over the contract extension period. At this time, however, the Company does not have a contract in place for power from Canal 1 beyond the existing contract period. Consequently, the Department finds that, for the purpose of determining need for additional resources, the capability contribution from Canal 1 should be included in the resource inventory only through the end of the existing contract period. The record indicates that the contract for power from Canal 1 is for a term of thirty-three and one-third years, expiring on October 31, 2001 (Exh. CON-2-4). However, the record does not contain evidence that would support the existence of any contract extensions beyond that date. Thus, the Department finds that the appropriate expiration date for the Canal contract is October 31, 2001.

The record indicates that, in calculating objective capability and capability responsibility, NEPOOL models the Hydro Quebec contract as an interconnection capability credit of 1800 MW, and assigns that capability credit among NEPOOL members. The record further shows that the Company has projected its share of the NEPOOL capability credit consistent with the 1800 MW value used by NEPOOL. Consequently, the Department finds that the Company has used a capability level for inclusion of Hydro Quebec through the end of the contract that is acceptable for the purpose of recognizing the contribution of existing and planned resources in meeting identified demands in this proceeding. However, the Department is concerned with the manner in which Hydro Quebec (in particular, the remaining tie-line benefit) is modelled by BECo for the purpose of calculating need beyond the end of the contract period. CONUG and the Company agree that there would be some CR (or reserve margin) reduction associated with recognizing the reliability benefits of the Hydro Quebec tie-line in NEPOOL's objective capability calculation for years beyond expiration of the existing firm energy contract, but the record does not clearly demonstrate what the appropriate tie-line benefit would be. The Department finds that there is no support on the record for the recommended 3 percent reserve margin adjustment recommended by CONUG. Consequently, for the purposes of this proceeding, the Department will not adjust the capability contribution assumed for Hydro Quebec over the planning horizon. However, the Company must make a clear presentation on this matter as part of its upcoming intercycle forecast.

c. <u>Existing Unit Reliability Uncertainties</u>

With respect to the CAAA, there are 215 MW of summer capability associated with the Company's combustion turbines that remain in question. The Department is concerned that the Company is relying upon decisions of the Massachusetts Department of Environmental Protection ("DEP") that have yet to be issued, and has not presented a plan to meet projected need levels in the event that such units are unable to operate at the time of system peak, as early as the summer of 1995. However, the Department notes that a need block inclusive of these MW could result in the solicitation for power that, ultimately, may not be needed, and that would carry commensurate costs for ratepayers. Further, even though DEP has not made final decisions on this and related issues, planning must proceed. Consequently, the Department finds that an adjustment to the base case resource inventory in consideration of the impacts of the CAAA is not appropriate at this time. Instead, the Department determines that the uncertainty surrounding implementation of the CAAA must be addressed in the context of the Company's reliability implementation strategy. <u>See</u> discussion on short-run adequacy in Section V, below.

The remaining reliability uncertainty issues addressed by parties in this proceeding include gas availability at New Boston Station, potential deratings of existing units, and the potential for the premature retirement of Pilgrim. With respect to New Boston Station gas availability, the record does not indicate that the Company is precluded by the consent decree from operating the New Boston 1 and 2 units on oil if needed at the time of winter peak, nor does the record contain any indication that NEPOOL intends to derate the units as a result of the Company's gas supply strategy for New Boston Station. Therefore, the Department finds that it would not be appropriate to reduce the existing resource inventory based on the gas procurement status at New Boston Station at this time.[34]

The record shows that the Company's units typically experience reductions in availability due to weather in the summer. The derating of existing facilities in weather conditions typical of summer peak could raise reliability uncertainties. It is not clear that the

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[34] The Department notes that the Company is negotiating for a natural gas supply to New Boston Station. Regardless of supplier, full operation of New Boston units on natural gas may be restricted by upstream transmission constraints. The record does not permit drawing firm conclusions on this question. Therefore, the Department directs the Company to provide additional information on this point in its intercycle filing. Specifically, if gas will be delivered over the transmission lines of Boston Gas Company and Algonquin Gas Transmission Company, the Company should address: (a) whether the 200 psig pressure limitation imposed by the gas distribution code, 220 C.M.R. §§ 100 <u>et seq.</u>, or by local grant of location would constrain operation between Cedar Road in Milton and Commercial Point in Dorchester (and possibly downstream of Commercial Point), resulting in a restriction on the full gas operation of New Boston units; and (b) whether the pipeline capacity between Algonquin's Ponkapoag take-station and Cedar Road (and elsewhere on Algonquin's system) is sufficient to supply full gas operation of the New Boston units. The information provided by the Company in Exh. CON-7-1 does not adequately answer these questions. BECo is also directed to provide complete information on whether it intends to revive its presently shelved plan to have Tennessee Gas Pipeline Company lay a transmission line across Boston Harbor to supply the New Boston plant.

NEPOOL Objective Capability calculation fully accounts for the potential for summer deratings; however, neither does the record support any specific adjustment that might accurately account for this factor. Therefor, for the purposes of this proceeding, the Department makes no adjustment with respect to summer unit deratings. In addition, the record indicates that repairs undertaken at Mystic station reduce the applicability of the 1986 Life Extension Study with respect to operation of Mystic 5. Consequently, for the purposes of this proceeding, the Department makes no adjustment with respect to the operation of Mystic 5.

The Department recognizes that the potential for early loss of the capability associated with operation of the Pilgrim plant poses an unknown risk for the Company's ratepayers. However, no evidence has been presented in this proceeding that persuades the Department that the operational safety or reliability of Pilgrim has changed since previous Department reviews of Pilgrim's operation. Thus, the Department finds that any uncertainties related to the continued availability of Pilgrim may be addressed through the Company's reliability implementation strategy, and do not warrant an adjustment to the Company's base case resource inventory in this proceeding.

In conclusion, the Department finds that it is not appropriate in this proceeding to apply a 100 MW reliability attrition factor to the existing resource inventory in consideration of the above uncertainties, as recommended by CONUG. However, the Department does find that the Company should take environmental compliance and unit performance uncertainties into consideration as part of its reliability implementation strategy. <u>See</u>

discussion in Section V, below. The inventory of existing supply side resources is as presented in Table 2.

C. Inventory of Planned Supply-Side Resources

1. Introduction

A planned supply-side resource is defined as a resource that is contracted for or has received preapproval but has not yet delivered KW or KWH to the electric company. 220 C.M.R. § 10.02. The IRM regulations require an electric company to apply attrition factors to planned resources to account for the contingency that planned resources may not meet the company's expectation for commercial operation dates. 220 C.M.R. § 10.03(7)(b)6. An electric company is required to provide sufficient documentation to explain its assumptions and methodology for predicting attrition of planned resources. Id. The Siting Council, in its Final Order on IRM Rulemaking, 21 DOMSC 93, at 133 (1990), did not mandate any particular methodology for predicting attrition of planned resources, and recognized that the appropriate methodology may vary from electric company to electric company, and from one IRM filing to another. The application of an attrition factor is not intended to change the inventory of planned resources, but will contribute to the determination of an electric company's resource need. Id. The Department has approved attrition methods that include percentages of planned resources based on identifiable milestones, and has rejected the use of additional mechanisms such as delaying inclusion of the MW contribution from planned resources in the planned resource inventory. Eastern Edison Company, D.P.U. 90-141, at 12-14 (1991).

2. The Company's Proposal

The Company has identified two projects in its inventory of planned supply-side resources: MBTA Jet Number 2 (23 MW) and Altresco (132 MW) (Exh. DPU-1-6, at 1). The Company asserts that it is appropriate to include the MBTA Jet Number 2 with a zero percent attrition factor to reflect an advanced level of development (Exh. BE-1-A at F.B.-14; Exh. DPU-1-6, at 2). With respect to Altresco, the Company states that it has "dealt with the uncertainty surrounding whether and when the Altresco plant will come on line by including it in our supply inventory at full capacity in 1999," and has addressed the potential unavailability of the Altresco plant in its scenario analysis (Exh. BE-1-A at B.2-2). BECo has been directed by the Department to enter into a contract for power from the Altresco facility, pursuant to the Company's third request for proposals ("RFP 3") under the QF regulations, 220 C.M.R. §§ 8.00 et seq. Boston Edison Company, D.P.U. 92-130 (1993); Boston Edison Company, D.P.U. 92-130-B (1994). BECo has appealed the Department's Order in D.P.U. 92-130-B.

3. Positions of the Parties

a. CONUG

CONUG asserts that the Department's pending Order on the Company's proposed contract with the MBTA will determine whether it should be included in the resource inventory (CONUG Brief at 65). However, CONUG contends that the Company's failure to apply any attrition factor to the Altresco project is inappropriate given BECo's extensive litigation campaign to thwart the project, and given that the Company itself has admitted that it is likely to be cost effective to buy out of the Altresco contract if it is ultimately forced to go forward with RFP 3 (id.). CONUG recommends that an attrition factor of 50 percent be used in this proceeding (id.).

b. Company

The Company contends that a Department requirement to apply an attrition factor to Altresco could lead to unacceptable results from a resource acquisition perspective (Company Reply Brief at 75). The Company asserts that, in the case of a single asset, the unit will either become operational or it will not, and that there is no such thing as a partial unit (id.). Therefore, the Company argues, to apply an attrition factor to Altresco assures a wrong result from a planning perspective (id.). BECo contends that it has met the Department's requirements by assigning an attrition factor of zero percent, accompanied by a clear explanation of its rationale for doing so (id. at 76).

4. Analysis and Findings

In Boston Edison Company, D.P.U. 93-164 (1995), the Department approved a contract submitted by BECo for power from MBTA Jet Number 2, effective immediately. Therefore, the Department finds appropriate the inclusion of 23 MW from MBTA Jet Number 2 in the Company's inventory of planned resources for the purposes of this proceeding.

The Department has directed the Company to proceed with its contract with the winner of RFP 3, Altresco. See Boston Edison Company, D.P.U. 92-130 (1993);[35] Boston

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[35] On February 23, 1994, the Department determined that the contract for the purchase of power from the Altresco facility was an executed approved standard contract in accordance with 220 C.M.R. § 8.03(1)(b).

Edison Company, D.P.U. 92-130-B (1994). The Department notes that BECo has appealed the Department's Order in D.P.U. 92-130-B.[36] The Department recognizes that there is considerable uncertainty regarding the inclusion of Altresco in the resource inventory. The Company has proposed to include Altresco in the resource inventory and address its uncertainty in a scenario analysis. The Department finds that this is an appropriate attrition methodology, at this time.[37] Given the many unique and controversial circumstances of the Altresco project, the Department finds that there is merit to the argument that, given there exists only a single facility to which an attrition factor would be applied, it is more appropriate to assess the future operation of Altresco on an all or nothing basis, and that Altresco should be included at 100 percent for the purposes of determining the MW contribution from planned resources in this proceeding.[38] Therefore, the Altresco facility is included in the resource inventory.[39] The Company's inventory of planned supply-side units is identified in Table 2.

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36 In addition, the Department notes that the Supreme Judicial Court vacated the Energy Facilities Siting Board's (successor to the Siting Council) approval of the Altresco facility. See Point of Pines Beach Association, Inc. v. Energy Facilities Siting Board, ___ Mass ___ (1995) (S6551).

37 In its intercycle filing, the Company will be able to update the disposition of the Altresco facility in its resource inventory.

38 In effect, an attrition rate of 0 percent.

39 The Company had proposed to include the Altresco facility in the resource inventory in 1999.

D. Existing and Planned Demand-Side Resources

1. Introduction

This section describes BECo's DSM resource inventory and identifies the anticipated MW contribution that BECo can expect from it during the planning period. The Department defines an existing DSM resource as "a resource that decreases the kilowatt or kilowatt-hour requirements of an electric company or that modifies the time pattern of customer capacity or energy requirements, and that has been installed at least one month prior to the date of the initial filing." 220 C.M.R. § 10.02. A planned DSM resource is "one that is contracted for or preapproved but has not yet begun to decrease the KW or KWH requirement of the electric company or modify the time pattern of customer capacity or energy requirements." Id.

2. Company Proposal

BECo claimed DSM savings attributable to a variety of programs, seventeen of which produced savings in 1993 (Exh. DPU-5-18(a)). In its Initial Filing, BECo claimed savings of 515 GWH of energy annually and 100 MW of summer capacity due to DSM measures installed from 1987 through 1994 (Exh. BE-1, at Table B.3-4). In addition, BECo is currently seeking preapproval for its 1995 programs (Tr. 8, at 41). BECo updated its estimated savings from existing installations to 481 GWH of energy annually and 93 MW of summer capacity due to existing DSM installations (Exh. DPU-5-18(c)). This updated estimate was based on (1) updated information on 1994 DSM activity, (2) findings in the Department's DSM goals Order in D.P.U. 91-233-C-1, (3) findings in the Department's DSM savings evaluation Order in D.P.U. 91-233-D, and (4) updated savings estimates from the Company's most recent impact evaluations (covering revisions to estimates of savings achieved by 1992 DSM program installations and a first evaluation of 1993 program savings) (Exhs. DPU-5-18(c); DPU-5-43). BECo stated that, if it had used earlier Department-approved estimates instead of the most recent impact evaluations,[40] estimated savings would be reduced by 1 GWH of energy annually and 10 MW of summer capacity (Exh. DPU-5-18(c); RR-DPU-24). BECo indicated that its most recent savings estimates are more appropriate than those presented in the initial filing, which reflected problems that were the basis for Department-ordered reductions to the savings that BECo had estimated in its filing in D.P.U. 91-233-D (Tr. 7, at 28-44).

3. Analysis and Findings

The record reflects that BECo has updated its DSM savings estimates to be consistent with Department Orders and with the latest information available on program activity and savings measurements. Therefore, for the purpose of calculating the Company's need for additional capacity in this order, the Department finds BECo's updated DSM savings estimates of 481 GWH annually and 93 MW at the summer peak, as the contribution from existing DSM resources, to be appropriate.

The record reflects that BECo's DSM programs for 1995 have not yet been preapproved by the Department, and therefore do not fit the definition of a planned resource.

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40 The earlier estimates of savings from 1992 installations were based on measurements at 1991 installations (Tr. 7, at 19-21). The most recent impact evaluations estimate savings from those same 1992 installations based on measurements at 1992 installations (id.).

The Department finds that BECo has no planned DSM resources, and will consider savings from 1995 DSM programs as a future resource.

E. Future Demand-Side Resources

1. Company Proposal

BECo projects savings from future DSM[41] (installations from 1995 through 2004) in similar increments each year, reaching 536 GWH of energy annually and 105 MW of summer capacity in 2004 (Exh. DPU-5-18(c)). BECo claims that it has followed the practice of all other Massachusetts utilities in including anticipated savings from future DSM resources in its IRM resource inventory, but acknowledges that this practice may not be entirely consistent with the IRM regulations (BECo Brief at 37). BECo argues that it should include a certain level of future DSM in the resource inventory, since the Department currently requires it to pursue all cost-effective DSM, regardless of its capacity position (id). BECo claims that the incremental capacity savings from future DSM contained in its projections are based on the continuation of current programs that have been preapproved by the Department, with minor modifications, and that the levels are reasonable (id. at 37-38).

41 Future DSM resources are anticipated DSM resources that meet neither the existing nor planned resource definitions.

2. Positions of the Parties

a. CONUG

CONUG argues that future DSM resources should not be included in a company's resource inventory (CONUG Brief at 59-64).[42] CONUG contends that Department precedent is not consistent with allowing savings from future DSM programs in a company's IRM resource inventory (id. at 60-61, citing D.P.U. 91-234, at 95). CONUG argues that the amount of energy savings due to future DSM installations is uncertain, since savings are a function of the number and type of installations, which are a function of avoided costs, which change with time (id.). CONUG argues that to include future DSM in a resource inventory would effectively create a "set aside" for DSM, allowing DSM resources to be added to a company's resource portfolio without having to compete with supply-side resources, thereby resulting in a suboptimal resource plan (id. at 62). Rather, CONUG maintains that DSM resources should have to compete with supply-side resources in the marketplace, via an RFP for capacity as a result of this proceeding (where CONUG expects a certain amount of DSM would prevail) (id. at 63-64).

b. MEEC

MEEC argues that future DSM resources should be included in a company's resource inventory (MEEC Brief at 2-6). MEEC observes that 220 C.M.R. § 10.03(8)(b) requires issuance of energy-only DSM RFPs, regardless of need for capacity (id. at 2). MEEC

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[42] CONUG acknowledges that resources from 1995 installations, for which BECo is currently seeking preapproval, might reasonably be included in BECo's resource inventory if an attrition factor is applied (id. at 59).

contends that to ignore the capacity contribution from DSM resources acquired pursuant to such RFPs would be an inappropriate "regulatory fiction" and would force electric companies to buy unneeded capacity (id. at 3, citing D.P.U. 91-234, at 95). MEEC maintains that BECo proposes continuing DSM at essentially steady levels[43] throughout the planning period, which is a natural outgrowth of Department requirements to pursue all cost-effective DSM programs (id. at 3-4).

c. Other Intervenors

Representative Marzilli likewise contends that all cost-effective future DSM resources should be included in the resource inventory for purpose of calculating resource need, consistent with Department regulations and the State Energy Plan (Marzilli Reply Brief at 2, citing State Energy Plan). To do otherwise, he contends, would overestimate resource need and commit ratepayers to unneeded supply resources (id. at 3).

The Energy Consortium contends that the contribution from future DSM resources should be reduced when there is no need for capacity savings, with a 50 percent DSM funding reduction for large customers in the G-3 rate class (Energy Consortium Reply Brief at 1).

3. Analysis and Findings

The Department has addressed the treatment of future DSM by stating that "it may be inappropriate, as a general matter, to ignore the capacity contributions from future DSM resources that may be cost-effective on an energy-only basis when calculating the size of the

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[43] MEEC contends that steady levels of DSM procurement reduce DSM costs (id. at 4-5, citing Exh. MEEC-2).

supply blocks for an all-resource solicitation under IRM." D.P.U. 91-234, at 95. BECo and MEEC have noted that Department regulations require electric companies to pursue all cost-effective DSM, including DSM that is cost-effective on an energy-only basis when no capacity need exists. 220 C.M.R. §§ 10.03(5)(a)5, 10.03(10)(c)2. The Department finds that it is reasonable to assume that DSM that is cost-effective on an energy-only basis will continue to be pursued and that such DSM will contribute MW savings, thereby reducing the level of capacity that the Company might otherwise have to purchase. The Department notes that BECo's projected annual savings contributions reflect steady increments of capacity savings and are consistent with levels achieved in the recent past and with levels preapproved in recent proceedings (D.P.U. 91-233-D at 84-85; Exhs. CON 8-13, CON 8-17). Therefore, the Department finds that it would be appropriate to recognize the capacity contributions from future DSM resources that can be anticipated to result from future energy-savings-only solicitations in this case.[44]

On December 22, 1994, the Supreme Judicial Court issued a decision vacating the Department's policy on environmental externalities values which is likely to affect the cost-effectiveness of the Company's DSM programs. See Massachusetts Electric Company v. Department of Public Utilities, 419 Mass 239 (1994) ("SJC Decision"). However, the record suggests that some of BECo's programs will remain cost-effective even without the benefit of avoided environmental externalities taken into account. The Department recognizes that the

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44 Pursuant to 220 C.M.R. § 10.07(5), the Department grants an exception to 220 C.M.R. § 10.03(7), which provides for resources that are in the resource inventory, for the reasons stated above.

Company may determine to discontinue those measures (and even some programs) that are no longer cost-effective, and, where opportunities are available, reallocate expenditures to more cost-effective measures.[45] The DSM RFP may provide an opportunity to procure DSM resources more cost-effectively. For these reasons, it is not clear at present whether the SJC Decision will lead to any reduction in DSM capacity savings. Therefore, for the purpose of this proceeding, the Department will accept the Company's estimate of savings due to future DSM resources in the calculation of resource need.[46] See Table 1. The Company is directed to submit in its next demand forecast revised estimates of future DSM savings based on its DSM RFP.

IV. DETERMINATION OF RESOURCE NEED

A. Introduction

In accordance with 220 C.M.R. § 10.03(8)(b), the Department assesses the Company's base-case need for additional capacity as calculated pursuant to a methodology that compares the resource inventory to the demand forecast. Pursuant to 220 C.M.R. § 10.03(8)(a), the Department may adjust or modify an electric company's evaluation of resource need consistent with the Department's findings on the demand forecast and resource inventory. See Sections II and III, above.

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45 On January 6, 1995, in D.P.U. 95-1-CC, BECo outlined its plans to revise its DSM programs in light of the SJC Decision. If adjustments relevant to this proceeding result from this process, BECo is directed to incorporate these adjustments in its intercycle filing.

46 Even if the Department were to accept no future DSM savings after 1995, the year of need would not change (see Table 1).

B. The Company's Proposal

The Company presented its base case need assessment by comparing the conclusions of its demand forecast with its resource inventory and the margin of reserve required by NEPOOL as presented in its filing (Exh. BE-1, at c.1-1). The Company concluded that it has a surplus of capacity in both the winter and summer of each year of the ten-year planning horizon, ending with a 169 MW surplus in the summer of 2004 (Exh. BE-7, Att. 11).

C. Positions of the Parties

1. CONUG

CONUG presents an assessment of the Company's need for additional capacity based on three alternative assumptions with respect to the Company's filing: (1) the July 21, 1994 peak did occur; (2) the economy and peak load will grow in 1995; and (3) the Company's generating units will perform as they have historically (CONUG Brief at 74). CONUG contends that these assumptions are straightforward, and are amply supported by the weight of the evidence on record (id.). CONUG presents a need calculation under these alternative assumptions through proposed adjustments (1) to the Company's projected reserve margin, and (2) to the expected MW contribution from the Company's existing and planned resources (id., Table 1). These adjustments are discussed in detail in Sections II and III, above, but are briefly summarized in this Section.

CONUG asserts that the Company's underforecasts of its loads and NEPOOL's loads grossly understate the required reserve margin. CONUG contends that its assessment of the Company's demand forecast before adjustments for DSM savings (see Section II above), requires that (1) the actual 1994 summer peak be substituted for the projected 1994 summer peak in projecting future Company loads (CONUG Brief at 31); (2) the projected rate of load growth for 1995 be changed from zero percent (as in the Company's forecast) to 2.1 percent -- less than one-half of the growth rates actually experienced in 1993 and 1994 (id. at 32); and (3) the annual growth rate projected through the year 1999 in the Company's forecast should be increased to 2 percent to reasonably account for the Company's underforecasting of employment, population growth, and appliance saturation (id. at 32-39). Further, CONUG contends that the Company has projected that NEPOOL's loads will increase by only 189 MW over the next three years, and then not grow at all over the subsequent eight years (id. at 44). CONUG asserts that this assumption serves to grossly understate the Company's required reserve margins (id.). CONUG thus concludes that the record supports an increase in the Company's reserve margins of at least 8 percent to compensate for the underforecasts of its loads and NEPOOL's loads (id.).

CONUG asserts that the reserve margin also should be adjusted to reflect the historical-average availabilities of the Company's units (see Section III above), and further adjusted to reflect a more reasonable assessment of the availabilities of the Company's NUG units and L'Energia (id. at 53-54). Finally, CONUG contends that the Company's projected reserve margins (1) fail to consider evidence that BECo's units likely will perform worse than they have historically; (2) do not factor in the Company's own assessment that Mystic 5 should be assessed an availability penalty of 19 percent if assumed to run at full output; (3) assume a reliable fuel supply for the New Boston units, even though the record shows the contrary; and (4) should reflect the Attorney General's demonstration that the cost and availability of Pilgrim will be worse, rather than better, in the future (id. at 54).

CONUG concludes that the weight of the evidence in this proceeding concerning the Company's forecasts of its loads and NEPOOL's loads, and concerning the projection of the performance of units in the Company's resource inventory, compels the rejection of the Company's proposed reserve margins, and supports reserve margins in the 28 to 30 percent range (id. at 54). However, CONUG asserts that the record does support a reduction in the reserve margin by three percent after the year 2000 to recognize the benefit of the Hydro Quebec tie after the expiration of the Hydro Quebec contract (id. at 56).

To complete its projection of resource need, CONUG adjusts BECo's projected capability by CONUG's recommendations (1) to include savings only from DSM measures installed through 1995 (id. at 64); (2) to remove the MW contributions from Canal 1 and Hydro Quebec at the end of their contract lives (id. at 56-57); and (3) to apply a 50 percent attrition factor to the Altresco Lynn project (id. at 65). CONUG further assesses a reliability attrition factor of 100 MW beginning in 1998 to account for capability uncertainties related to unit summer deratings, capability of New Boston 1 and 2 at peak, Mystic 5 derating, impacts of the CAAA on Company units, and the potential for premature retirement of Pilgrim (see Section III, above) (id. at 73-74).

Under CONUG's alternative need calculation, BECo has a capability deficiency of 73 MW in 1995, growing to as much as 1020 MW in 2001 (id., Table 1).

2. Company

The Company maintains that, in reviewing the basis for the Company's assertion that certain reserve margins are required, the Department should focus on the underlying CR calculation assumptions in order to determine whether or not the Company has properly planned for its future resource needs (Company Reply Brief at 36). The Company states that this is appropriate since the CR calculation not only is used for retroactive billing adjustments, but also is used by NEPOOL and members of NEPOOL in planning for future requirements (id. at 39). In support, the Company notes that NEPOOL has produced a document that projects CR values and associated parameters through the year 2000 (id.). The Company asserts that the record demonstrates that BECo has fully explained and justified the CR calculation that establishes the basis for its resource needs over the planning horizon (id. at 36).

The Company disputes CONUG's assertions concerning the need determination with respect to (1) the forecasts of BECo and NEPOOL load growth; (2) the performance of existing units; and (3) remaining resource inventory issues. The Company states that CONUG's assertions concerning the impacts of load growth on projected required reserve margins are flawed and unsupported by record evidence (id. at 41-43). The Company contends that CONUG's assertion that the Company has assumed NEPOOL's load will not grow after 1997 is wrong and misrepresents the record (id. at 43-44). The Company concludes that CONUG has offered little support for its conclusions concerning the Company's load growth assumptions and reserve margins (id. at 44-45).

As discussed above, the Company rejects the positions taken by CONUG and the Attorney General with respect to unit availabilities, and the manner in which Hydro Quebec is included in the need calculation (see Section III, above). The Company concludes that it has appropriately addressed unit availabilities for the purposes of projecting resource need with respect to its fossil and nuclear units, as well as L'Energia (Company Reply Brief at 79-80). The Company asserts that it has included Hydro Quebec correctly, and that CONUG's proposed reliability adjustment for the Hydro Quebec tie of 3 percent after 2000 is not supported by the record (id. at 67).

Finally, as discussed in previous sections, the Company contends that it has treated existing and planned resources -- including Canal, Altresco Lynn, New Boston Station, and DSM -- correctly for the purpose of calculating resource need (see Section III, above). The Company asserts that the 100 MW reliability attrition factor proposed by CONUG must be rejected since it is not provided for under the Department's regulations, and since it lacks supporting evidence in the record (Company Reply Brief at 76-77).

The Company concludes that it has fully documented its assumptions regarding reserve margins, unit availability, resource inventory, and all other factors of the resource need calculation (id. at 79), and that CONUG's need calculation is not supported by substantial evidence and must be rejected (id. at 80).

D. Analysis and Findings

The Department's finding on resource need derives from the findings presented above on projected demand (Section II) and the existing and planned resource inventory (Section III). 220 C.M.R. § 10.03(8). Consistent with the findings on the demand forecast and resource inventory, the Department determines the Company's need for additional capacity in the base case in the following manner. First, the total capacity requirements for each year of the planning period are calculated by multiplying the projected peak demands (identified by the Department in Section II) by the reserve margins that are consistent with 5 years of recent actual EAFs as presented by the Company in Exh. AG-2-24 (in accordance with Department findings in Section III). Next, the Company's proposed resource inventory is reduced to reflect removal of the MW contributions from the projected operation of Canal beyond October 31, 2001, and savings from DSM measures are assumed to be consistent with those presented by the Company in Exh. DPU-5-18(c). Finally, for each year in the planning horizon, the Department-approved resource inventory is subtracted from the Department-approved total capacity requirements (in accordance with Department findings in Sections II and III). The Department's findings on the Company's projected demand and resource inventory, and the resultant need are presented in Tables 1 and 2. These tables reflect a resource need of 16 MW in 2001, growing to 165 MW in 2004.

V. RESOURCE PLANNING AND PROCUREMENT

A. Introduction

The IRM regulations set out the specific filing requirements for, and evaluation by the Department of, the electric company's resource need. 220 C.M.R § 10.03(8). From a deterministic perspective, an electric company's need for additional resources can be assessed by comparing projected system loads to the existing and planned resources that will be available to meet those loads. However, a comprehensive resource planning process requires detailed analysis of the factors that drive future load levels and those that affect contributions anticipated from a company's existing and planned resources. An appropriate planning process must reflect established least-cost planning principles and recognize and account for the uncertainties inherent in any forecasting process.

A sound resource plan has three essential components. First, a methodology must be developed that provides a theoretically sound basis for determining future resource requirements. A necessary part of this process is the development of a methodology for identifying a reliability planning target that strikes an appropriate balance between system reliability and the costs of meeting alternative reliability levels. Second, appropriate input data must be selected and processed in a manner consistent with that methodology to produce dependable projections of future resource needs. Third, a least-cost implementation strategy must be developed for procuring resources necessary to achieve the reliability objectives prescribed through the first two steps of the process. 1992 BECo Decision at 235-236.

In the following sections, the Company's reliability planning process is evaluated to determine whether its planning methodology and the application of that methodology are appropriate. Next, the Company's resource procurement implementation strategies are reviewed in order to ensure compliance with long-run system reliability and least-cost planning objectives, while addressing any system adequacy concerns in the short-run.

B. Resource Planning Methodology

1. Company Proposal

BECo evaluated a set of nine scenario analyses in its resource planning process, in an attempt to deal with changes in the electric industry and with a range of forecast uncertainties in a way that would be understandable and usable by its management (BECo Brief at 8). The six demand-side scenarios evaluated by BECo were economic boom, electrotechnology breakthrough, electric market competition, switch of cooling load to gas, economic bust, and high fuel prices (Exh. BE-1, at C.3-5).[47] The three supply-side scenarios evaluated by

[47] The analysis presented in BECo's initial filing indicated that the first two scenarios would lead to a capacity deficiency beginning in 1996, while the other four would

BECo were (1) unit performance at historical EAF levels, (2) no Canal contract extension and no Altresco Lynn unit, and (3) the loss of Pilgrim starting in 2000 (id. at C.3-6).[48] BECo also analyzed the costs of using short- and long-term power purchases to respond to any needs that might arise under six alternatives: its base case with and without Altresco Lynn, its economic boom scenario with and without Altresco Lynn, and its economic bust scenario with and without Altresco Lynn (id. at C.4-2 through C.4-7). BECo concluded from its analysis that short-term commitments had lower costs in the base case and economic bust scenario, but slightly higher costs than the long-term commitment strategy in the economic boom scenario (id. at C.4-2). BECo determined that it would be appropriate to pursue flexible short-term commitments in response to any contingencies that might arise (id. at C.4-2). BECo also proposed to issue an Options RFP (discussed below) in order to secure resources beginning in 1998 (BECo Reply Brief at 101, citing RR-DPU-50).

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lead to a capacity surplus throughout the planning period (Exh. BE-1, at C.3-5). The economic boom scenario showed slightly greater demand growth (over three years) than any experienced by BECo in the last 20 years, while the economic bust and high fuel cost scenarios showed considerably larger contractions in demand than any experienced by BECo in the last 20 years (Exhs. DPU-5-56, DPU-5-57, and DPU-5-59).

48 BECo's initial filing indicated that the loss of Pilgrim would produce the largest capacity deficiency and unit performance at historical EAF levels the smallest (Exh. BE-1, at C.3-6). The capacity deficiencies begin in 2004 for the historical EAF scenario and in 2000 for the other two scenarios (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that BECo's resource planning process inadequately considers the risks of high costs for power in the future (Attorney General Brief at 5-6). The Attorney General maintains that BECo has not prepared contingency plans to respond to cost increases (due to environmental risks, loss of baseload capacity, or high fuel prices) or minimize the risk of cost increases (id. at 10-11). The Attorney General argues that BECo has not developed contingency resources that are cost-related (e.g., purchase options)[49] rather than demand-related (e.g., load management, capacity purchases) (id.). The Attorney General also argues that BECo's reliance on scenario analysis fails to recognize that there may be value in pursuing risk-mitigating energy resources, such as DSM, renewable resources,[50] and distributed generation[51] (id. at 6).[52] The Attorney General contrasts BECo's contingency scenarios to an alternative methodology that integrates probabilistic

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[49] An option to purchase involves a payment to acquire the right, but not the obligation, to purchase power for a (larger) specified price at a future date (Exh. BE-4, at 20).

[50] Renewable energy resources include solar, wind, hydro (water), wood, and trash.

[51] Distributed generation, in contrast to central station generation, includes DSM, energy storage technologies (e.g., batteries and flywheels), fuel cells, and renewable resources such as wind and solar photovoltaic power (Exh. CLF-1, Att. 6).

[52] According to the Attorney General, the benefits of DSM, renewables, and distributed generation include smaller increments of capacity, shorter lead times, greater security of supply, reduced fuel price risk, little or no risk of capacity loss due to environmental regulations or unit emissions, and the ability to more cost-effectively follow increases and decreases in customer load (Attorney General Brief at 8).

analysis[53] with the results of contingency analyses and with the costs of various strategies by which to respond to identified contingencies (id. at 6-10). The Attorney General maintains that BECo should consider both expected costs and variability in costs (id. at 10). The Attorney General contends that BECo should assess several strategies, such as "high DSM," "small additions," and "over-build," to meet contingencies (id. at 10). The Attorney General faults BECo for (1) failure to consider some of its greatest contingency risks, (2) overreliance on the assumption that low energy prices will continue, (3) insufficient attention to the effect that future environmental requirements may have on plant retirements, and (4) failure to consider possible combinations of contingencies[54] (id. at 8-9). The Attorney General urges BECo to assess fully the relationship between contingencies and the costs and availability of resources assumed ready to meet those contingencies (id. at 9).

b. CONUG

CONUG contends that BECo's scenario analysis does not meet the statutory requirement to provide high and low load forecasts and sensitivity analyses of major planning assumptions (CONUG Brief at 16, citing Tr. 6, at 30-43). CONUG maintains that BECo's scenarios are unrealistic and that BECo avoids analysis of reasonably likely contingencies (id. at 17). CONUG requests that the Department apply the regulatory requirements to analyze

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[53] The Attorney General contends that the Company must estimate probabilities in order to value options that would be bid in the Company's proposed options RFP (Attorney General Brief at 9).

[54] For example, the Attorney General contends that the combination of an economic boom, increased environmental regulation, and a reduced contribution from nuclear generating units could quickly eliminate any regional capacity surplus (Attorney General Brief at 10).

reasonably likely contingencies in its assessment of BECo's need for additional capacity (id. at 17-18).

c. CLF and MASSPIRG

CLF and MASSPIRG maintain that BECo's planning process is deficient in that it omits actions necessary now to ensure the availability of future resource options that will be lowest in cost, accounting for environmental impact and fuel diversity (CLF/MASSPIRG Brief at 6). CLF and MASSPIRG contend that BECo has failed to use the most recent information about the cost, reliability, and potential of renewable resources (id. at 9-10, 13-14). CLF and MASSPIRG also claim that BECo's resource planning process takes a "wait and see" approach to environmental matters, rather than planning for contingencies such as possible future regulations requiring increased restrictions on emissions of NO_x, air toxics, fine particulates, and CO_2 (id. at 18-19). CLF and MASSPIRG contend that BECo has not developed contingency plans to ensure a least-cost response to contingencies involving future environmental regulations, nor has it considered the effect of future environmental regulations on the availability and cost of surplus power in the region (id. at 21, 25).

d. Energy Consortium

The Energy Consortium maintains that it would be appropriate to take some additional risks to reduce costs, in order to increase long-term economic growth in the BECo's service territory (Energy Consortium Reply Brief at 1).

e. Representative Marzilli

Representative Marzilli agrees with the Attorney General that BECo should include in its resource plan protection against future cost increases, by pursuing more DSM and renewable resources (Marzilli Reply Brief at 2).

f. BECo

BECo contends that its nine scenarios represent a sound basis for reliability planning and satisfy those portions of the IRM regulations that require that sensitivity analyses be provided (see 220 C.M.R. § 10.03(6)(e)) (Exh. DPU-7-2; BECo Brief at 10). The Company states that its scenario analysis approach is superior to a probability-based decision tree analysis, which was endorsed by the Attorney General (BECo Brief at 10). BECo claims that its scenario analysis enables Company management to better focus on how to react to future contingencies (id. at 9). In addition, BECo claims that its approach to planning provides improved clarity compared to the "black box" of probabilistic analysis (id.). BECo also asserts that its approach offers the economic advantage of flexibility in advancing and deferring resource acquisition decisions, as well as avoiding the difficulty of assigning probabilities to "essentially political" events (id.). BECo contends that its proposed Options RFP could secure resources, should they be needed, to respond to contingencies as appropriate (BECo Brief at 64).

3. Analysis and Findings

The IRM regulations do not specify a particular planning methodology. 220 C.M.R. § 10.03(8). BECo has employed scenario analysis as its resource planning methodology. BECo has analyzed a number of scenarios and the relative costs of two strategies to address three of those scenarios. The Attorney General advocates use of probabilistic decision-tree scenario analysis. Noting how uncertain forecasting can be, the Department accepts scenario analysis as a useful planning tool, especially if combined with sensitivity analysis.

However, the record demonstrates several weaknesses in BECo's implementation of scenario analysis. First, the record shows that BECo presented only nine contingencies; these included only one combined contingency, no contingencies involving environmental requirements, and no contingency involving a substantial price decrease for electricity. The Department finds that BECo's set of contingency scenarios is too limited and does not constitute a full and systematic evaluation of all the reasonable contingencies to which it may have to respond. Second, the record shows that BECo did not assess the likelihood of any of its contingencies occurring. The Department finds that some such assessment (even if subjective, but informed) would be useful to place the various contingencies and potential response strategies into perspective. Third, the record shows that although BECo identified six strategies to respond to contingencies, BECo did not identify and analyze other clearly possible response strategies, such as those cited by the Attorney General. Moreover, the record shows that the Company's response strategy focused on the current capacity surplus in the region, which might be reduced by certain foreseeable combined contingencies, such as an economic boom combined with increased environmental regulation. Fourth, the record shows that BECo analyzed the costs of only two strategies to meet contingencies identified in only three of its own scenarios. The Department finds that this limited analysis leads to only minimal consideration of the trade-offs between the expected costs of various combinations of contingencies and response strategies and the risks to ratepayers of high costs. Therefore, based on BECo's presentation, the Department cannot determine whether BECo might reduce the risk to customers of substantial increases in future costs, for relatively little increase in cost, or conversely, whether a slight increase in cost risk or reliability risk might yield a substantial cost savings. However, the Department recognizes that an appropriately designed options RFP could be a valuable part of the Company's strategic planning process.

Noting the weaknesses in BECo's implementation of scenario analyses, the Department directs the Company to continue its efforts to improve its planning methodology for its next IRM filing.[55] This methodology should evaluate a fuller range of contingencies and combined contingencies, estimate the likelihood of their occurrences, and examine a wider range of strategies to respond to them. The methodology also should analyze the expected costs of the wider range of contingencies and strategies, in order to highlight the trade-offs between lower expected costs and lower risks of higher costs. The Company should also explain more fully how DSM, treated as a contingency resource, could enhance its resource plan. The Department also directs the Company in its next resource plan to continue its efforts to address the availability of its contingency resources under the various scenarios considered.

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55 Given the uncertainty concerning the Altresco facility, the Company should update its disposition in its intercycle filing.

C. Resource Procurement Strategies

1. Introduction

The Department's IRM regulations indicate that a resource solicitation will occur to meet an identified need for additional resources, consistent with the characteristics of that need. 220 C.M.R. § 10.03(8)(b). The Company is expected to develop a strategy to meet its obligation to provide reliable electric service to ratepayers at the lowest total cost to society. Accordingly, the Department evaluates the appropriateness of issuing an RFP for supply-side resources, in light of the findings above on the Company's need for additional capacity and the characteristics of that need. The Department also evaluates reasonable contingencies that may confront the Company in the short run. In demonstrating the adequacy of its supply plan in the short run, a company must identify the action plan by which it would respond to the foreseeable contingencies that may result in a need for additional resources above the level consistent with an approved reliability planning target. D.P.U. 91-234, at 118.

2. RFP for Capacity Based on Need Findings

a. Introduction

When the Department has identified a need for additional capacity resources, competitive solicitations are conducted in order to "determine the mix of resources that is most likely to result in a reliable supply of electrical service at the lowest total cost to society." 220 C.M.R. § 10.03(10)(a). The IRM regulations indicate that an RFP should solicit resources to meet the level of additional need identified for each year of the ten years following the Company's initial filing date, and that the RFP should be consistent with the other elements of the Company's initial filing. 220 C.M.R. § 10.03(8)(b)(2). If the Department finds that a solicitation is required to meet an identified need, but issuance of the company's RFP as submitted is not in the public interest, the company shall revise its proposed RFP as required by Department order. 220 C.M.R. § 10.03(11)(d).[56]

b. Company Proposal

BECo claimed that the Company has no need for additional capacity during the planning horizon (Exh. BE-2, at 2). Accordingly, BECo maintains that no RFP for capacity should be issued in this IRM cycle (Exh. BE-2, at 2; BECo Brief at 61; Exh. BE-13, at 13). Rather, BECo plans to respond to any capacity needs through flexible short-term purchases from surplus capacity in the region, possibly supplemented by acquisitions from its proposed Options RFP (Exh. BE-2, at 2; BECo Brief at 61-66; Exh. BE-1, at C.4-2).

Nevertheless, BECo included a draft RFP for additional capacity in its initial filing "for discussion purposes only," in order to comply with the terms of the settlement agreement in D.P.U. 92-265 (BECO Brief at 62; Exh. BE-13, at 5). The Company stated that if the Department finds a need for capacity in this proceeding, the Company would modify the RFP presented (Exh. CON-3-13).

56 In addition, the IRM regulations provide that, if no capacity need is identified during the planning period, an RFP shall be issued for energy or energy savings only. 220 C.M.R. § 10.03(8). However, the Department determined in D.P.U. 93-154, at 11, that an energy-only RFP would not be required for companies which participate in the short-term energy market.

c. Positions of the Parties

i. CONUG

CONUG contends that the Company does have a substantial need for additional capacity, and that BECo should be required to issue a capacity RFP in response to any capacity deficiency identified by the Department during the ten-year planning horizon (CONUG Brief at 75). CONUG maintains that the capacity RFP should be open to all comers, including owners of any surplus capacity in the region (id. at 3). CONUG asks that any buy-out and deferral decisions pursuant to the results of BECo's proposed RFP be subject to Department review (id. at 84). CONUG also argues that BECo's estimate of six years as the time necessary to build a new plant[57] is too short, based on actual experience over the last few years (id. at 3).

ii. Other Intervenors

The Attorney General agrees with BECo that there is probably no need to issue an RFP for capacity at this time, citing the risk of financial commitment to new central generating plant (Attorney General Brief at 11, citing Exh. AG-1, at 4). Likewise, the Energy Consortium, which is concerned about high rates, agrees with BECo that additional supply-side capacity is not required at this time (Energy Consortium Reply Brief at 1).

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57 BECo presented a list of lead times ranging from 16 to 41 months for eight particular projects currently in the permitting cycle (Exh. BE-1, at C.3-25). BECo also estimated lead times of 31 to 48 months for four generic types of gas-fired plants and 69 months for a generic coal plant (id.).

iii. BECo

BECo contends that, in light of dramatic changes in the electric utility industry (DSM, increased wholesale competition, retail wheeling, acid rain mitigation, electromagnetic fields, new technologies such as electric cars, and new regulatory structures), it is important for the Company to maintain the flexibility to respond to whatever contingencies may develop (BECo Brief at 2, citing Exh. BE-1, at 1-4 and Exh. BE-2, at 1-12). BECo claims that, since it has no need for additional capacity during the planning horizon, that there is a large regional surplus of capacity, and that the lead time for new capacity is only 2 1/2 to 6 years, no RFP for capacity should be issued in this IRM cycle (id. at 60-61, citing Exh. BE-1, at C.3-24 and C.3-25).

d. Analysis and Findings

Table 1 reflects the Department's findings regarding BECo's need for additional resources through the planning horizon. It indicates resource deficiencies beginning with 16 MW in 2001 and growing to 165 MW in 2004.

The Department notes that the deficiencies identified (1) are modest relative to the total capability of BECo's resource inventory and (2) appear late in the forecast period. The record suggests that lead times for new resources are relatively short compared to the period of time before substantial additional capacity is likely to be required. Moreover, as BECo has emphasized, the electric utility industry is in a period of considerable change.[58] To the

[58] The Department has recognized the changing nature of the electric utility industry in other proceedings. See Notice of Inquiry and Order Seeking Comments on Incentive Regulation, D.P.U. 94-158 (1994); Mergers and Acquisitions, D.P.U. 93-167-A (1994).

extent that the Company's supply portfolio were to become subject to the competitive forces of an increasingly deregulated generation market, shareholders and ratepayers would bear the risk that any additional investments might be unmarketable.[59] Further, as discussed below, the Company's proposed Options RFP could secure resources during the time period when a resource need has been identified. For the reasons stated above, the Department finds that ratepayer interests would not be served by requiring BECo to issue a conventional capacity RFP pursuant to the IRM regulations at this time.[60] See D.P.U. 91-234, at 124-125.[61]

3. DSM RFP

a. Introduction

Pursuant to the IRM regulations, an electric company is required to solicit resources to meet any additional resource need identified for each year of the ten calendar years following the Company's initial filing date. 220 C.M.R. § 10.03(8)(b)(2). The IRM regulations state that, if no additional capacity need is identified for the planning period, then the RFP shall be for energy or energy savings only. Id.

Evident throughout the Department's Orders addressing resource procurement is the expectation that competitive processes will yield the lowest cost resources for ratepayers.

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59 The Department recognizes that, even in a regulated market, excess capacity is costly to ratepayers.

60 Pursuant to 220 C.M.R. § 10.07(5), the Department issues an exception to the requirement that resources be solicited to meet the additional resource need identified for each year of the planning period. See 220 C.M.R. § 10.03(8)(b).

61 The record shows that BECo participates in the short-term energy market (Exh. BE-12, at 1; RR-DPU-46). Therefore, the Department will not require the Company to issue a supply-side energy-only RFP in this IRM proceeding. See D.P.U. 93-154, at 11.

See D.P.U. 89-239, at 1-5 (1990); D.P.U. 86-36-F at 37-48 (1988). However, the Department has recognized that a host electric company might have a substantial incentive to distort a resource solicitation so as to create a process that would result in the selection of its own resource proposal over proposals that would be selected through a truly competitive process. D.P.U. 86-36-F at 62-64. Therefore, to ensure that fair, competitive solicitations occur, the IRM regulations call for the Department to review (1) prospectively, in Phase I of the IRM proceeding, an electric company's proposed RFP(s) and proposed resource selection process; then (2) retrospectively, in Phase III of the IRM proceeding, a company's implementation of the approved resource selection process and the resulting award group. 220 C.M.R. § 10.03; 220 C.M.R. § 10.05. This IRM review framework was designed to (1) balance the conflicting goals of providing for a flexible resource procurement procedure and ensuring that company decisions would be sufficiently reviewable to preclude host company self-dealing; (2) enable the Department to determine whether the resources to be preapproved represent the most reliable and least-cost resource mix; and (3) minimize and simplify future Department reviews of award-group ranking and disqualification disputes.[62]

To meet the objectives outlined above, an RFP must contain all information necessary for project developers to understand and compete fairly in the company's solicitation process. 220 C.M.R. § 10.03(10)(a). In particular, an RFP must explain the ranking system and any other component of the company's process for selecting project proposals for the award group, as well as the negotiation and contracting procedure. 220 C.M.R. § 10.03(10)(c).

[62] See, e.g., D.P.U. 86-36-C at 111-112 (1988); D.P.U. 86-36-F at 61-64, 76-78; D.P.U. 86-36-G at 13-50 (1989); and D.P.U. 89-239, at 29-36.

The IRM regulations further state that the "RFP shall specify the amount of additional resources being solicited by the company in both megawatt ("MW") and megawatt-hour ("MWH") (or MW and MWH saved) per year and season based on the size and timing of the resource need identified." 220 C.M.R. § 10.03(10)(c)2.

Finally, the IRM regulations address an electric company's requirements with respect to its initial resource portfolios. 220 C.M.R. § 10.03(5). Pursuant to the regulations, companies are required to include, in their Initial Resource Portfolios, cost-effective DSM programs that target all customer sectors and subsectors and that minimize lost opportunities. 220 C.M.R § 10.03(5)(a)(5).

In D.P.U. 86-36-F at 7, the Department stated that "electric companies should pursue -- through purchase, expenditure, or investment -- [DSM] and generation options to the extent that such actions are cost-effective for each company's ratepayers." The Department further specified that DSM programs should be designed to capture all potential lost opportunities, avoid cream-skimming, and distribute the direct benefits (i.e., reduced energy and/or load requirements) as broadly as possible among customer classes and subgroups within each class. Id. at 25, 26.

In D.P.U. 91-80 Phase II, the Department stated that it is

> "sensitive to some of the negative impacts arising from intense implementation of C&LM [conservation and load management], and we recognize that it may not always be feasible for a ... company to procure the optimal amount of C&LM within a short time period. The Department concludes that aggressive C&LM programs can create significant inequities between program participants and non-participants, and can cause negative customer reactions to utility-sponsored C&LM programs. Although the Department remains committed to C&LM, we find that it is appropriate for a company to balance

> the competing goals of establishing aggressive program penetration targets (i.e., optimizing the resource portfolio), and controlling ratepayer bill impacts.

Id. at 38.

In determining the level of information required regarding a company's initial resource portfolio, the Department sought to strike a balance between "the need to prevent self-dealing [by the host company] and the desire to ensure that utility-sponsored projects are not put at a [competitive] disadvantage." D.P.U. 86-36-G at 37. The Department found that the requirement that a company submit all information required of RFP respondents except for price, method of cost-recovery, and cost information "satisfactorily balanced the competitive interests of utilities and other providers .... [A]ll parties would know in advance the resource the utility would develop in the absence of third-parties ... and the company would have to settle on a final price proposal ... at precisely the same time that other project developers would be required." Id. at 39.

b. The Company's Proposal

The Company submitted an RFP for Conservation Proposals (Exh. BE-1, Book 2, Section D-1). The Company stated that the proposed RFP was developed consistent with the Department's regulations and with the Company's commitment to providing a full range of cost-effective DSM programs (Exh. BE-6, at 15). The proposed RFP would subject all of the Company's programs to competitive solicitation, based on energy blocks for 1996 and 1997 in five separate market segments: (1) Residential Retrofit, (2) Residential Lost Opportunity, (3) Large Commercial/Industrial ("C/I") Retrofit, (4) Small C/I Retrofit, and (5) C/I Lost Opportunity (id. at 15-16). In addition, BECo has allocated a percentage of the retrofit resource blocks for "Customer Generated Proposals" to all individual BECo customers to continue their own DSM efforts (id. at 16). Proposals received in response to the RFP would be evaluated using the Department's societal cost-effectiveness test, utility and customer cost tests, and five separate resource selection criteria: (1) Price Factor, (2) System Quality Optimization Factor, (3) Timing Factor, (4) Project Development Feasibility Factor, and (5) Operational Longevity Confidence Factor (id.). The RFP would not solicit proposals for Load Management or Conservation Voltage Regulation programs (id. at 16-17).

c. Positions of the Parties

i. MEEC

MEEC asserts that, as filed, the DSM RFP does not satisfy the requirements of the IRM regulations (MEEC Brief at 6). In particular, MEEC contends that the DSM RFP fails to include an initial resource portfolio as required by 220 C.M.R § 10.03(10)(c)(10), and fails to meet the requirements of 220 C.M.R § 10.03(10)(a) to include sufficient information for project developers to understand and compete fairly in the solicitation process, and to solicit all information necessary to compare DSM proposals (id. at 6-7).

MEEC generally asserts that the DSM RFP omits important information and contains substantial flaws of clarity and consistency, fails to adequately account for the differing characteristics of the various market segments, and is not well suited to ensuring that all policy goals are met, including comprehensiveness and service to hard to reach sectors (id. at 7-8).

MEEC also provides a number of specific comments regarding the DSM RFP, which can be summarized as follows:

(1) The front load security amounts are excessive and should be reduced (id. at 9-10);

(2) The Company should revise the scoring of major criteria, as well as the subscoring within each major category, in order to place greater weight on non-price criteria and to better match the scoring system to each market sector (id. at 10-11);

(3) The bid scoring system and a description of how non-price factors will be integrated with the Company's analysis of the proposals' system impacts should be included and described in the DSM RFP (id. at 11-12);

(4) The evaluation and contract negotiation procedures of the DSM RFP should be modified and more clearly described (id. at 12-13);

(5) The Company's initial resource portfolio must be attached to the DSM RFP (id. at 13);

(6) The DSM RFP should explicitly disclose the Company's role as a bidder (id. at 13);

(7) The Company should engage an independent evaluator acceptable to the Department to assist in the Company's bid evaluation process and to report to the Department (id. at 13-14);

(8) The DSM RFP should include additional information concerning the characteristics and conservation potential of each market segment to help reduce the informational advantage of the Company and its existing vendors (id. at 14);

(9) The Company should communicate to bidders relevant goals or policy considerations, and should include in the RFP avoided costs, sample calculations of security, and an updated solicitation schedule (id. at 14-19);

(10) The Company should revise preapproval procedures and the milestone schedule, and adjust the Long-Run Standard Contract to be consistent with all DSM RFP revisions (id. at 15-16);

(11) The Monitoring and Verification Protocols should be further reviewed, refined, and clarified by the Company (id. at 16-18); and

(12) The Company should be required to submit its final bid one day before other bids are due, and should not be able to update its bid after other bids have been received (MEEC Reply Brief at 6).

MEEC concludes that the Department should order the Company to submit a complete, revised DSM RFP to the Department for review and approval, and that the Company should be allowed the full 60 days permitted by the IRM regulations to do so (MEEC Brief at 19). Finally, MEEC suggests that the Department should encourage the Company to consult with outside parties in revising its DSM RFP before filing it with the Department (id. at 20).

ii. CLF and MASSPIRG

CLF and MASSPIRG assert that the Company's DSM plan in general, and the DSM RFP in particular, emphasizes retrofit programs over lost opportunity markets, and that lost opportunities for savings will result (CLF/MASSPIRG Reply Brief at 9). CLF and MASSPIRG recommend that the Department postpone implementation of the proposed DSM RFP until the Company is able to implement a revised DSM strategy consistent with its recommendations concerning market transformation and other lost opportunities, and that competitive solicitation for DSM services should then be structured to maximize delivery of cost-effective savings consistent with the DSM plan in the least-cost manner (CLF/MASSPIRG Brief at 45).

iii. Company

The Company states that there is a level of DSM that is cost-effective on an energy-only basis, and that it is necessary to maintain a certain amount of continuity in the delivery of DSM services to maintain a DSM infrastructure (Company Brief at 54). The Company states that the proposed DSM RFP will enable the Company to select those conservation programs which will most cost effectively and reliably satisfy BECo's resource requirements, but that the Company expects that certain changes to the DSM RFP would improve the likelihood of achieving the Company's goals (id. at 55-56). In particular, the Company states that, if the Department does not order the Company to issue both supply- and demand-side RFPs, the Company would assign different weights to the DSM RFP criteria to place more emphasis on the non-price factors (id. at 56). Also, the Company asserts that it would be appropriate to modify certain procedures for lost opportunity programs, monitoring and evaluation protocols, and comprehensiveness thresholds, and that it would hold a pre-bid conference to address bidder concerns (id. at 56-58). Finally, the Company states that it continues to assess whether the DSM RFP provides all information necessary for bidders to understand and compete fairly in the solicitation process (id. at 58).

The Company rejects CLF and MASSPIRG's proposal to postpone the DSM RFP, noting that such action is not consistent with the IRM regulations and prior Department directives (Company Reply Brief at 82). In addition, the Company presents substantial agreement with a number of the recommendations made by MEEC with respect to the DSM

RFP, but argues that the necessary modifications can be made to the existing DSM RFP, without revising it in its entirety (id. at 81-82).

The Company disagrees with the recommendation by MEEC that an independent evaluator is appropriate, asserting that the Company intends to evaluate all bids, including its own, evenhandedly, and that the Department's proceeding in IRM Phase III will ensure that the solicitation process will be subject to full review (id. at 91-92). The Company also disagrees with the recommendation by MEEC that avoided costs be provided, and asserts that doing so could result in bids that are only marginally below avoided costs, thereby increasing the cost of DSM programs to the Company's ratepayers (id. at 93). Finally, based on a review of the various points raised by MEEC and the Company's own assessment of the necessary modifications to the DSM RFP, the Company agrees with MEEC that it should be allowed 60 days to file a revised DSM RFP with the Department (id. at 95).

The Company proposes to present an initial resource portfolio with a revised DSM RFP, but requests the opportunity to update its bid to improve program designs (id. at 90-91). The Company argues that including improvements that may be found in the time between submittal of its initial resource portfolio and the date when other bids are due could enhance DSM programs by lowering costs or improving quality (id. at 91).

d. Analysis and Findings

The Department notes that the Company is in agreement with many of the recommendations of MEEC, and has proposed to submit a revised DSM RFP to the Department for review. The Department accepts the Company's proposal to revise its DSM RFP.

In constructing its DSM RFP, the Company should consider the concerns identified by MEEC with respect to the DSM RFP that pertain to factors that could affect the interest and participation of potential bidders to the DSM RFP. The level of participation of potential bidders may ultimately affect the cost and quality of DSM programs administered in the Company's service territory.

Moreover, the Company has identified significant potential changes in the electric industry, which the Department finds may warrant a reevaluation by the Company of its strategies for DSM implementation.[63] The Department notes that electric company DSM efforts could be substantially affected by the potential for increasing competition in the electricity markets. The Company should construct its DSM RFP with particular attention to the extent to which DSM strengthens the competitiveness of the Company's resource plan, and should thus focus on the overall rates charged by the Company and the effects that the implementation of DSM will have in enhancing the Company's abilities to attract and retain customers. The Company should ensure that the DSM RFP provides a clear presentation of the scoring procedures for project selection criteria, and of the overall resource selection process, and should include the Company's initial resource portfolio as required by the Department's regulations at 220 C.M.R. § 10.03(5)(a).

63 In addition, as the Department has noted in Section III.E. above, the SJC Decision vacating the Department's environmental externalities values is likely to affect the cost-effectiveness of the Company's DSM implementation.

4. Resource Need Uncertainties

a. Short-Run Adequacy

i. Standard of Review

The Department reviews the short-run adequacy of an electric company's supply plan in Phase I of IRM proceedings. 220 C.M.R. § 10.03(11)(e). The short run is defined as the time period extending four calendar years from the year in which the initial filing is submitted. Id. In order to establish adequacy in the short run, an electric company must demonstrate that it owns or has under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies, or that it operates pursuant to a specific action plan which would guide its acquisition of necessary resources in the event of foreseeable contingencies. Id. Contingencies such as the loss of the largest unit on a company's system, responding to a high case load growth, and failure of anticipated new supplies to enter commercial operation may result in a need for additional resources above the level consistent with an approved reliability planning target. See D.P.U. 91-234, at 118.

ii. The Company's Proposal

BECo stated that it utilized its contingency planning process to examine the potential resource need in a range of planning scenarios and concluded that there are ample contingency resources available to meet any potential capacity shortfall (Exh. BE-1, at C.3-1). The Company contended that this supports a finding that its supply plan is adequate in the short run (BECo Reply Brief at 95-96). BECo examined a range of contingencies using scenario analysis (Exh. BE-1, at C.3-8). BECo identified nine scenarios in its Initial Filing, reflecting alternative demand assumptions or supply assumptions (see

Section IV.C., above), two of which, economic boom and a breakthrough in electric technology, resulted in modest capacity shortfalls in 1996 and larger (5 percent to 9 percent of BECo's projected capability responsibility to NEPOOL) shortfalls in 1997 and 1998 (Exh. BE-1, at C.3-5). BECo did not identify any scenarios that simultaneously changed demand and supply assumptions (Exh. DPU-5-55). However, BECo identified two scenarios in which increased demand diminished the current regional surplus (RR-DPU-20; RR-DPU-51).

BECo identified six types of responses that it could employ to meet a need for capacity if it should arise. BECo maintained that it could (1) rely on the current surplus capacity in the region (which BECo asserts is between 2,000 and 4,000 MW), (2) increase its load management programs (up to 60 MW more), (3) "pre-site" plants to shorten construction lead times, (4) upgrade transmission capabilities to neighboring regions, (5) introduce real-time pricing to reduce load at times of high demand, and (6) tolerate a greater likelihood of outages due to insufficient generating resources (Exh. BE-1, at 19 and C.3-2 through C.3-4; Exh. BE-2, at 5).

In addition, BECo has proposed to issue an experimental "Options RFP," by which it would explore the possibility of purchasing options to acquire additional capacity in the future (BECo Brief at 64-65, citing RR-DPU-50; see also Section V.C.4.b, below). BECo contends that its proposed Options RFP will enable it to take advantage of the regional surplus capacity and will give it "the necessary flexibility to deal with a variety of potential contingencies" (BECo Brief at 64-65, citing RR-DPU-50). BECo claims that the options identified would enable it to respond rapidly to possible economic and industry changes (BECo Reply Brief at 102).

iii. Positions of the Parties

(a) CONUG

CONUG contends that BECo's supply plan is inadequate in the short run (CONUG Brief at 85). CONUG identifies a wide range of events that could lead to a capacity shortfall in the short run, four of which are reviewed below (id. at 32-73). First, CONUG claims that the load growth rate will be higher than that forecast by BECo and that BECo's 1995 peak may be 60 MW higher than the 1994 peak (id. at 32). Second, CONUG argues that BECo's fossil units may perform worse than they have in the recent past, rather than better as BECo claims, and that Pilgrim may fare no better than it has in the recent past (id. at 52). Third, CONUG argues that BECo may not be allowed to operate its combustion turbines (215 MW of summer capacity) beginning in 1995 (id. at 70-73). Fourth, CONUG maintains that unit deratings at BECo units of several hundred MW, due to high ambient temperatures, could be expected under summer peak conditions (id. at 66, citing Exh. CON-2-23).

CONUG also contends that the presentation of a realistic demand forecast for the region, which properly incorporates the 1994 summer peak, would demonstrate that no large regional surplus exists (id. at 76, 81, citing Exh. CON-2-6). CONUG contends that environmental compliance issues may substantially affect units owned by other utilities, which, combined with increased demand, could eliminate any regional surplus (id. at 81-83).

(b) Attorney General

The Attorney General identifies several contingencies that may confront BECo, including the early shutdown of Pilgrim (which the Attorney General contends is more likely than not by 2003) and the full or partial unavailability of the New Boston or Mystic 4, 5, and 6 generating units (id. at 13-19, citing Exh. AG-1, Att. 3).

(c) CLF and MASSPIRG

CLF and MASSPIRG raise the possibility that BECo may not be allowed to operate its combustion turbines (CLF/MASSPIRG Brief at 19-20). CLF and MASSPIRG suggest that controls may be required for air toxics and/or very fine particulates, both of which could affect BECo's capacity position in the short run (id. at 22-24). CLF and MASSPIRG claim that BECo has framed no plans to meet these contingencies (id.).

iv. Analysis and Findings

For purposes of this proceeding, the short run includes the years 1994 through 1997. The base case need findings, exhibited in Table 1, show a capacity surplus, falling from 266 MW to 90 MW (eight percent to three percent of peak demand), throughout the short-run period. As indicated above, a short-run adequacy review first requires an assessment of whether the Company has sufficient resources to meet its CR under a reasonable range of contingencies. In assessing whether BECo has sufficient resources to meet its CR under a reasonable range of contingencies, the Department notes that BECo has identified two scenarios which result in a capacity shortfall starting in 1996 (economic boom and electrotechnology breakthrough). The record in this proceeding also indicates that BECo faces many contingencies that could reasonably occur together.[64] Therefore, in assessing adequacy in the short run, the Department evaluates the following combined contingency: an increase in demand affecting BECo, calibrated to the actual 1994 summer peak, combined with the unavailability of 215 MW from BECo's combustion turbines starting in 1995.

The Department finds that this particular contingency, in the context of the Department's need findings, could result in a 105 MW capacity shortfall in 1995. For this short-run contingency scenario, the resources which BECo owns or has under contract would not be sufficient to meet its CR to NEPOOL. Therefore, the Department's adequacy review turns to BECo's action plan.

The record shows that BECo's action plan is to rely principally on the current surplus of capacity in the regional market by making short-term purchases as needed. The Department finds that the Company's action plan is acceptable. Nonetheless, since some contingencies could reduce the regional surplus on which the Company relies, the Company's action plan could be enhanced by further (and continuing) assessment of potential responses to short-run contingencies. The Company's proposed Options RFP, if modified to render it capable of responding to short-run contingencies, may provide an additional opportunity to

64 Among the contingencies identified by the parties are an economic boom or strong economic recovery which affects the entire region, higher load growth for BECo alone, increased demand from new electrotechnologies, deterioration in fossil plant performance generally, an extended outage at Pilgrim, unavailability of BECo's combustion turbines, thermal deratings of units at summer peak, unavailability of New Boston in the winter, unavailability of one or more Mystic units, and contingencies related to potential future environmental requirements.

procure economical power in the short run, in the event of certain contingencies, and could add a new and useful dimension to the Company's ongoing strategic planning activities.

b. The Proposed Options RFP

i. Company Proposal

BECo proposes to issue an experimental options RFP to secure resources should they be needed to respond to any contingencies that materialize (BECo Brief at 64). For a price (the "option" price), BECo could obtain the right, but not the obligation, to acquire capacity and/or energy at a definite date in the future at a larger price (the "strike" price) established in a bid (id. at 65). BECo's proposed Options RFP would seek options to buy approximately 250 MW of capacity and energy, preferably in 50 MW increments, with initial delivery of power between 1998 and 2003 (id. at 64-66, citing RR-DPU-50). BECo states that it would be an all-resource RFP, open to any type of bidder (id.). BECo indicates that it would have no obligation to either purchase any options or purchase any power (i.e., exercise any option at its strike price) (id.). BECo proposes to issue the Options RFP by March 1, 1995 and report the results to the Department within one year (id.).

BECo states that a minimum of regulatory oversight would be necessary for the Options RFP and that a preapproval process would be unnecessarily time-consuming (BECo Reply Brief at 102). However, BECo does not "fundamentally oppose" Department review (id.).

ii. Positions of the Parties

(a) Attorney General

The Attorney General believes that BECo should identify and acquire resources that mitigate risk and reduce cost, including more DSM, distributed and renewable resources, and options for resources (Attorney General Brief at 6). The Attorney General urges the Department to require BECo to issue an options RFP for resources to be available in the period 1996-2000 (id. at 25-26). The Attorney General argues that such an options RFP should be reviewed and approved by the Department before issuance, and should be conducted on a fixed schedule, but with no fixed amount of resources to be purchased (id. at 26, citing RR-DPU-50; Tr. 20, at 115). The Attorney General identifies a concern regarding the recovery of costs related to the acquisition of options or other risk-mitigating actions and suggests that this may be appropriate subject-matter for settlement agreement (Attorney General Brief at 26). The Attorney General further argues that BECo should prepare and present to the Department a supply RFP that could be issued in the event that a major contingency occurs (id. at 27).

(b) Other Intervenors

CONUG did not address the issue of an options RFP. However, in the context of an RFP for capacity need, CONUG stated that it was not opposed to buy-out and deferral provisions in an RFP (CONUG Brief at 83-84). CONUG argued that, to have a resource option available when it is needed in the future, a decision to purchase a resource option must be made now (CONUG Reply Brief at 2-4).

The Energy Consortium supports the Options RFP, provided BECo would not purchase any option unless there is a realistic potential for a contingency that could be addressed by that option (Energy Consortium Reply Brief at 2). The Energy Consortium advocates that the Options RFP be open to DSM projects and cogeneration projects (id.). Representative Marzilli also supports the proposed Options RFP (Marzilli Reply Brief at 2).

iii. Analysis and Findings

The record demonstrates many uncertainties in the demand forecast and resource inventory which constitute significant contingencies that may affect the Company's capacity position in the short and the long run. The Department finds that an options RFP, properly designed and managed, could allow the Company to prepare for a variety of contingencies. It also could allow the Company to take advantage of any low-cost surplus capacity currently available. Further, the Department finds that an options RFP could be an effective management tool which could allow the Company an opportunity to examine whether there are ways to reduce its cost and address the risks that are inherent in the marketplace. The Department recognizes that an Options RFP represents an innovative approach to resource planning. If this approach is successful, it will no doubt be of general interest in the industry. Therefore, the Department accepts the Company's proposal to issue an options RFP.[65]

[65] To the extent that the Options RFP could be construed as issued as a result of this IRM proceeding, pursuant to 220 C.M.R. § 10.07(5), the Department issues an exception from the requirement that the RFP shall be approved by the Department before it is issued by the Company. 220 C.M.R. § 10.04(2).

The Department recognizes that this RFP lies within the responsibility of Company management. The Company should construct its Options RFP in a manner that permits bids from all resource providers[66] to be given fair and reasonable consideration. Of course, in this regard, this does not reflect any change from our current policy. The Company should inform the Department of the issuance and results of its options RFP, as well as the purchase of any options.

The Department anticipates that any prudent costs incurred to purchase options for the acquisition of necessary resources would be recoverable through a company's rates for electric service. If an option is exercised to procure an incremental resource, the resulting costs would be recoverable if, in keeping with established planning principles, an electric company demonstrates that exercise of the option is part of a least-cost resource plan.[67]

D. Other Resource Procurement Issues

a. Renewables RFP

i. Positions of the Parties

(a) Attorney General

The Attorney General urges the Department to require BECo to issue a renewables RFP, in order to take advantage of the environmental, diversity, and flexibility benefits of renewable resources (Attorney General Brief at 27). The Attorney General maintains that

[66] The options RFP should be a fair market test of a reasonable array of options, whether demand or supply.

[67] One way to demonstrate that the exercise of an option is part of a least-cost resource plan is to subject it to a competitive test. See D.P.U. 93-112-A at 17.

this RFP should be limited, to ensure that rate impacts are minimized (id. at 27). The Attorney General claims that a renewables RFP is supported by the Massachusetts Energy Plan and would provide risk mitigation benefits which have been recognized by the Department (id. at 28).

(b) Representative Marzilli

Representative Marzilli claims that BECo's failure to include a renewables RFP in its resource plan is inconsistent with state energy policy (Marzilli Reply Brief at 1-2).[68] Representative Marzilli asks the Department to require BECo to issue a renewables RFP, claiming that such an RFP would protect ratepayers against future cost increases (id. at 2).

(c) CLF and MASSPIRG

CLF and MASSPIRG urge the Department to require BECo to issue a renewables RFP for 25 to 45 MW of capacity (CLF/MASSPIRG Brief at 16). CLF and MASSPIRG also claim that the lack of a renewables RFP in BECo's filing is inconsistent with the Massachusetts Energy Plan and therefore with the statute governing this case (id. at 8-9, citing G.L. c. 164, § 69I). CLF and MASSPIRG asserted that BECo's customers prefer environmentally clean resources and believe that BECo is not doing enough in this area (Exh. CLF-1-13, Att. 1, at 18-19; RR-DPU-68, at 22; Tr. 19, at 223). CLF and MASSPIRG contend that BECo has overestimated the cost of renewable resources and

68 The Massachusetts Energy Plan states, "To ensure that energy resources are least cost, and our regulatory processes support timely and efficient implementation of new environmentally compatible resources, state government will work to ... accelerate the development and procurement of ... renewable energy technologies" (Marzilli Reply Brief at 1-2, citing Massachusetts Energy Plan at 8).

underestimated their potential (CLF/MASSPIRG Brief at 12-14, citing Exh. CLF-2, at 8 and Att. 2; Exh. BE-14, Att. 3; and Exh. DPU-13-1-S). CLF and MASSPIRG estimate the maximum net cost in any one year of the renewable resources that would result from their proposed renewables RFP to be only 0.264 percent of BECo's 1993 revenue requirements (id., citing RR-BE-1, Att. 1).

(d) BECo

BECo maintains that an RFP open exclusively to renewable resources has some advantages, but may not be cost-effective at this time (id. at 72; BECo Reply Brief at 104). BECo states that it intends to continue to monitor events and to continue to examine additional opportunities to pursue renewable resources (BECo Brief at 72).

ii. Analysis and Findings

The record suggests that the procurement of renewable resources may provide some advantages in an electric company's resource plan. The record is not clear that renewable resources would represent least-cost additions to BECo's resource plan at this time. Therefore, the Department will allow, but not require, the Company to pursue a renewables RFP as part of this proceeding. The Company should inform bidders in such a renewables RFP that it has no obligation to accept any bids. The Company may choose to specifically solicit renewable resources as part of its options RFP. If the Company elects to issue a separate renewables RFP within the IRM process, any resultant contracts should be presented to the Department for review and approval as part of a least-cost/least-risk resource plan. If the Company chooses to pursue renewable resources outside of the IRM process, it should be prepared to demonstrate that any resultant contracts (1) could not have been acquired through an IRM solicitation and (2) are in the best interests of ratepayers. See Massachusetts Electric Company, D.P.U. 94-46, at 24 (1994). See also D.P.U. 89-239, at 47.

b. Market Transformation

i. Positions of the Parties

(a) CLF and MASSPIRG

CLF and MASSPIRG contend that BECo should improve the cost-effectiveness of its DSM program by emphasizing investment in lost opportunity resources[69] with the goal of market transformation[70] (CLF/MASSPIRG Brief at 27-28). CLF and MASSPIRG claim that a strategy emphasizing lost opportunities and market transformation would be more cost-effective than BECo's emphasis on retrofits (id. at 28, citing Exh. CLF-1, at 8). CLF and MASSPIRG assert that market transformation would reduce or eliminate the long-term need for ratepayer investment in areas where market transformation permanently removes market barriers (id. at 28, citing Exh. CLF-1, at 9). CLF and MASSPIRG contend that BECo ignores opportunities for market transformation (id. at 30). CLF and MASSPIRG enumerate five opportunities for BECo to engage in market transformation: participation in efforts to (1) upgrade national appliance efficiency standards, (2) improve state building code standards

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[69] Lost opportunities include new construction and equipment replacement programs, as well as remodeling programs by some definitions.

[70] Market transformation in DSM can be defined as initiatives which cause a substantial increase in market share for energy efficient equipment to meet the same needs as less efficient equipment. Examples of market transformation strategies include utility promotion of variable speed drive motors, utility-funded development of a super-efficient refrigerator, government standards mandating efficient electronic ballasts for fluorescent light bulbs, and building codes requiring more insulation (Exh. CLF-1, Att. 2).

and enforcement, (3) design super-efficient appliances, (4) devise efficiency standards for equipment not currently covered, and (5) review market barriers and ways to overcome them (id. at 30-31). CLF and MASSPIRG argue that capacity and energy savings from market transformation efforts by BECo could be measured and attributed to BECo, given sufficient time for measurement methodologies to be developed and for market transformation to occur (id. at 32-36).

(b) BECo

BECo claims that it has supported and continues to endorse the goals of market transformation, including support for improved building code standards (BECo Brief at 69). BECo contends that it does not get credit for savings generated by its market transforming DSM programs, because the savings from the transformation is not measured (id. at 69-70; Tr. 7, at 71-73). Moreover, BECo asserts that savings from its programs that it could otherwise claim are reduced by the effects of market transformation, as the calculated gains from efficient equipment installed through the Company's programs are reduced by comparing the efficient equipment to the more efficient baseline (the transformed market) caused by the Company's past efforts (id.). BECo states that successful market transformation changes the baseline of standard practice (against which savings are measured), making it unclear how to measure savings, as well as difficult to attribute a particular amount to a particular electric company (BECo Brief at 70). BECo asserts that market transformation takes place over a number of years and therefore is not amenable to measurement within the IRM process (id.). BECo also claims that the capacity and energy savings that CLF and MASSPIRG believe could be achieved by pursuing market transforming DSM programs are unrealistically high (id.).

ii. Analysis and Findings

The Department agrees with the parties that market transformation may offer some benefits, including improved cost-effectiveness for many DSM programs. However, the record shows that the effects of market transformation have not been measured reliably yet and are difficult to attribute to any particular utility company. Therefore, the Department will not require a change to BECo's DSM programs or to the design of its DSM RFP.

c. Distributed Generation

i. Positions of the Parties

(a) Intervenors

CLF and MASSPIRG and the Attorney General advocate that BECo better analyze the benefits of distributed generation and integrate more of distributed generation technologies into its system (CLF/MASSPIRG Brief at 40-41, citing Exh. CLF-1, Att. 6; Attorney General Brief at 21-22, citing Exh. AG-1, at 58-59). CLF and MASSPIRG urge that BECo include in its resource plan distributed generation resources that are cost-effective compared to planned transmission and distribution ("T&D") investments (CLF/MASSPIRG Brief at 41-42). CLF and MASSPIRG suggest that BECo initiate a pilot project that would explore the use of DSM and environmentally clean distributed generation to defer T&D investments. The Attorney General contends that BECo undervalues the risk-mitigation benefits of distributed generation (i.e., small increments, short lead times, lack of fuel costs, no risk of large cost overruns, low or no emissions, avoided line losses, and T&D costs) (Attorney General Brief at 21-23).

(b) BECo

BECo attributes advantages and disadvantages to distributed generation, and states that it expects to pursue it more extensively, citing its interest in flywheel storage systems as an example (BECo Brief at 69). BECo claims that it already considers distributed resources when performing cost-effectiveness tests for T&D system improvements (id.). BECo adds that it anticipates implementing a pilot program to test distributed resources within the next two years (id.).

ii. Analysis and Findings

The record indicates that there are advantages and disadvantages to distributed generation, and that distributed generation is cost-effective in selected applications. Therefore, the Department directs the Company to continue its pursuit of distributed generation resources, focusing on opportunities which enhance the cost-effectiveness and efficiency of its energy supply system.

VI. ORDER

As indicated above, the Department has found that: the July 15, 1994 demand forecast of the Boston Edison Company is approved; the inventory of existing and planned, supply- and demand-side resources is as set forth in Table 2 of this Order; the reliability planning process presented by the Company in this proceeding is deficient in that it does not include a methodology for identifying a reliability planning target that strikes an appropriate balance between system reliability and cost, and therefore that the Department cannot accept the planning methodology or resultant resource need projections presented by the Company; the Company's need for additional capacity resources is, for the purpose of this proceeding, as calculated in Table 1 of this Order.

Accordingly, after notice, hearing and consideration, it is hereby

ORDERED: That Boston Edison Company shall not be required to issue an RFP for additional capacity or capacity-savings as a consequence of this Phase I IRM review; and it is

FURTHER ORDERED: That Boston Edison Company shall not be required to issue an energy-only, supply-side RFP as a consequence of this Phase I IRM review; and it is

FURTHER ORDERED: That Boston Edison Company shall, no later than March 13, 1995, submit a DSM RFP consistent with the directives contained herein for Department review; and it is

FURTHER ORDERED: That Boston Edison Company shall, no later than March 13, 1995, submit its DSM initial resource portfolio consistent with the directives contained herein for Department review; and it is

FURTHER ORDERED: That Boston Edison Company shall submit an intercycle forecast filing consistent with the Department's directives on January 2, 1996.

FURTHER ORDERED: That the Boston Edison Company shall comply with all Orders and directives contained herein.

By Order of the Department,

____
Kenneth Gordon, Chairman

____
Mary Clark Webster, Commissioner

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).